BEFORE THE NEBRASKA PUBLIC SERVICE COMMISSION

In the matter of Aquila, Inc.	)	
d/b/a Aquila Networks ("Aquila")	)	Docket No. NG-
seeking a general rate increase	)	Docket No. NG-
for Aquila's Rate Areas One, Two	)	Docket No. NG-
and Three (not consolidated)	)	

Direct Testimony of Jerl Banning

Director of Compensation and Organizational Development

Variable Compensation

November, 2006

Jerl Banning
20 West 9th Street
Kansas City, MO 64104
816-467-3619

Introduction

Q. Please state your name and business address.

A. My name is Jerl Banning, and my business address is 20 west 9th Street, Kansas City, MO.

Q. By whom are you employed and in what capacity?

A. I am employed by Aquila, Inc. as Director of Compensation and Organizational Development.

Q. What is your academic background?

A. I received a B.A. in Psychology from Bethel College in Newton Kansas, and a M.A. in Organizational/Personnel Psychology
University of Kansas. After completing my Masters Degree, I continued at the University of Kansas completing all of the required course work and the oral comprehensive examination toward a Ph. D. but began my career prior to completion of the required dissertation.

Q. Please briefly describe the duties of your present position.

A. I direct the activities of the corporate compensation function, as well as training and development, diversity, relocation and other corporate wide human resource functions.

Q. Please summarize your employment experience.

A. Beginning in 1986, I worked as a Human Resource consultant for ten (10) years including time with the following professional service firms; Ernst & Young, DeFrain Mayer Lee & Burgess, and William M. Mercer. In 1996, I accepted a corporate position with Koch Industries. In 2000, I joined the Human Resources Department at Aquila.

Q. What is the purpose of your testimony?

A. To explain Aquila's general compensation process and variable compensation programs, and to support recovery of the compensation related expenses of Aquila's employees.

Variable Compensation

Q. Please explain Aquila's compensation philosophy and guiding principles.

A. In 2004, Aquila revised its Total Compensation and Benefits policies to reflect its current business strategy. The reason for the revision was and is to ensure that Aquila's compensation policies are designed not only to be fair to employees but also to recognize a focus on providing good service to the customers and communities in which Aquila serves.

The following bullet points are intended to represent the essence of that revised philosophy as it applies to employee base pay and variable compensation:

- Aquila's compensation philosophy and practices are intended to help attract, retain, and motivate employees to achieve appropriate business results.
- Each component of Aquila's pay practices (both base and variable compensation) should be competitive at the median of the relevant labor market.
- Base pay is intended to reflect the market median of the labor market and the individual's sustainable performance levels over time.
- Variable compensation should also reflect the market median as well as the individual's contribution to business unit and company results.
- Aquila's compensation programs are intended to be open and transparent and the metrics utilized for recognizing performance should inspire confidence in Aquila among its customers and the communities it serves.

Q. How is this philosophy applied to Nebraska?

A. To affect and execute that philosophy, Aquila's Human Resource ("HR") professionals and managers work in concert to meet the desired business issues and concerns. The compensation staff at Aquila participates in a variety of published pay survey's to gather applicable information on the market pay and practices relevant to the industry. The local HR representatives of Aquila, including its Nebraska HR representative, gather local information from relevant employers and provide that information to Aquila's corporate compensation managers to be used in the analysis of Aquila's relative pay position within that market. Aquila compensation managers, with the help of their local Human Resource Representatives, including its representative in Nebraska, then execute on the philosophy by exercising their experience and judgment to fit the local business conditions within the parameters of the pay policies and practices established by the corporation.

Q. Please explain Aquila's philosophy on base pay compensation.

A. Base pay is intended to reflect the median of the market for similar positions in similar companies. There are thirteen (13) pay grades which are used for all non executive jobs in Nebraska. Each grade has a minimum, midpoint, and a maximum pay range. Executive positions are placed within the executive bands according to market data and practices. All jobs are compared to the market, where data exists, and placed in the grade where the midpoint of the range is closest to the average market rate for that job. An employee's pay moves within the range based upon their performance and their time in the job. Aquila Human Resources reviews the pay structure annually to see how the structure and pay practices reflect the market. A primary component of the annual analysis is a metric called a Comparison ratio, which compares Aquila's overall average pay to the average market pay. This ratio provides a sense of Aquila's overall base pay compared to market. A second important metric compares Aquila's midpoints of the pay ranges for the jobs in each grade to the market average pay for those jobs. This metric indicates how well Aquila's base pay structure fits the market. As of September 9, 2005, the average base pay for employees in Nebraska was 98% of the market, indicating Aquila employees base pay rates were slightly below but within acceptable range of the market. As shown in Exhibit ____(JB-1), the Aquila's pay structure mid-points for Nebraska employees in each grade was 93% of the average market for similar positions indicating Aquila's structure is about 7% below the market pay for employees in Nebraska. Exhibit____(JB-2) lists the data sources utilized in Aquila's market comparison analysis.

Q. What is the reason for variable compensation?

A. The purpose or Aquila's Variable Compensation plan is to provide competitive incentive opportunities that are consistent with other companies in the industry, and to focus employees on important performance objectives. Aquila's variable compensation plan helps to ensure its total pay position is competitive with market practices for Aquila employees, that its total compensation expense varies with the Company's performance on measures important to the customers, and it provides a tool to align employees interests with customer and community interests. Aquila's Variable Compensation Plan rewards employee performance on three categories. Those three categories or variable compensation factors include the following performance categories: company performance, state performance, and individual performance. The relative weight of these three factors is dependent upon an employee's level within the company and their ability to influence the outcomes of the measures. At lower levels in the company, 80% of the individuals' award is tied to individual performance objectives. The higher an employee's position, the more weight is placed on State and Company goals.

Q. How are the incentive targets set in the Variable Compensation Plan?

A. Aquila's establishes its incentive targets to achieve the market median incentive opportunity of similar companies. The goal is to provide its employees with a *total* compensation package that is competitive with other companies when Aquila achieves target performance levels on operational goals. Over the past few years Aquila's variable compensation targets and payouts have been below the average variable compensation payouts in the market. In 2006, Aquila adjusted its incentive targets to get closer to the market average incentive payouts in the industry. It has retained its focus on customer service and community support, but needs to make sure that it also attracts and retains qualified employees to provide the customer support and service required by Aquila. The 2005 and 2006 targets and weightings as compared to market are listed in Exhibit ___(JB- 3). A description of the mechanics, and a sample calculation of how the 2005 and

2006 Aquila Variable Compensation Plan work, are provided in Exhibits _____(JB-4) and _______(JB-5).

Q. Please explain the metrics of the Variable Compensation Plan.

A. The metrics for the variable compensation plan in 2005 and in 2006 reflect operational goals that are important to our customers in Nebraska. Individual goals are established at the beginning of each year and reflect the individual's responsibilities. The Corporate metrics for 2005 were based upon Reliability of Service, Safety, Customer Service, Effective use of Capital and Process Improvement.

Q. Were any changes made for 2006?

A. The 2006 corporate goals are similar but Process Improvement was replaced with Reducing On-going Costs of Service. Again, these goals are important metrics for our company and our customers and are reviewed and adjusted each year to reflect the important objectives for that year. The Reliability Goal includes Emergency Response Time, Network Reliability, SAIDI, SAIFI, CAIDI, and Base Generation Station Availability. The Safety measures include chargeable vehicle incidents and lost time injury incidents, both of which have implications for cost and service to customers. The Customer Service measure includes meters read, accuracy of meters read, customer service call time, and emergency service call times. Effective use of Capital is measured by EBITDA – Capital Expenditure. It measures our ability to provide earnings after completing our budgeted capital expenditures. The manager is awarded for meeting his/her budgeted capital investment and providing additional earnings which serves to increase our credit rating and reduce Aquila's cost of capital and in turn, reduces the service costs to our Nebraska customers. The Process Improvement Goal (2005) and the Reducing On-going Cost of Service (2006) rewards focuses employees on identifying additional opportunities to increase process efficiency and effectiveness for our customers.

Q. Has Aquila's Variable Compensation Plan Been Approved by Public Service Commissions in which Aquila Provides Service?

A. Yes. This basic compensation structure has been used by Aquila for almost two decades. The components of the Variable compensation factors are revised from time to time, but several different state utility commissions have reviewed and approved this compensation structure over the years.

Aquila's variable compensation is a critical part of an employee's compensation. An alternative compensation practice would be to move the variable compensation into the employee's base pay, but that structure would not provide for the same incentives as is built into the current structure.

The cost of the Variable Compensation is measurable within a range established each year. Thus, while the compensation level itself may vary from year to year depending on the fulfillment of the required objectives, the minimum and maximum payouts are known and measurable.

By its definition, Aquila's *variable* compensation programs are not measurable at the beginning of the performance period. The purpose of the plan is to ensure that total compensation expenses, vary somewhat with important metrics of Company performance. The 2006 plan is designed specifically around performance on metrics most important to the customer. So, when the Company and the employee are doing very well for the customers' benefit their pay is a little more. When the Company and the employee are not doing as well for the customers, their pay is a little less. We firmly believe that tying performance metrics that benefit Aquila customers is the best way for Aquila to manage it's compensation expense. Remember, the primary objective of Aquila's compensation philosophy is to ensure our pay packages are competitive to attract and retain employees needed to provide service.

Aquila is aware of other utilities that provide incentive or variable compensation as part of their compensation packages. Without a similar plan, Aquila's total compensation package may not be competitive with other utilities.

State regulators appear to understand and agree that an alternative to variable compensation would be for Aquila to raise all employees base pay to reflect the median variable compensation earnings provided by other utilities. While this would provide a competitive total compensation rate that is “fixed and measurable”, it would de-link those costs with customer performance measures and increase overall costs as many of our benefits are also tied to base pay rates. Instead, Aquila’s variable compensation plan is beneficial for the customers, as it seeks employee focus on the Customer whether all of the company and personal objectives are met or not. For these reasons, Aquila includes that expense is justified for recovery as part of its regulated rate recovery.

Q. Please summarize your testimony.

A. Aquila’s total compensation philosophy is intended to provide pay opportunities at the 50th percentile of similar utilities. Our base pay practices in aggregate fall just short, but in range of that target in Nebraska. Our variable compensation targets are also somewhat below the market opportunities provided in our industry. Our variable compensation payouts are based on important operational objectives and are weighted according to the level of the employee and reflecting outcomes the individual can influence. Most of the variable compensation payout is based upon individual goals and objectives for the year. At the corporate and state level these goals reflect operational metrics including reliability, customer service, safety, effective use of capital, and reducing on-going costs to customers. We believe our variable compensation program encourages employees to focus on what our customers want and therefore improves the service we provide in Nebraska. We also believe the total expenses associated with these plans are reasonable, comparable to other utilities, and should be fully recovered in rates.

Q. Does this conclude your testimony?

A. Yes.

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Direct Testimony of Philip M. Beyer

Director of Benefits and Human Resources Information Systems

Pension Expense

November, 2006

Philip M. Beyer
20 West 9th Street
Kansas City, MO 64104
816-467-3462

Introduction

Q. Please state your name and business address.

A. My name is Philip M. Beyer, and my business address is 20 W. 9th Street, Kansas City, MO 64105.

Q. By whom are you employed and in what capacity?

A. I am employed by Aquila, Inc. as Director of Benefits and Human Resources Information Systems. In that capacity, I am responsible for managing the overall plan design, cost and administration of Aquila's employee benefit plans and Human Resources Information Systems.

Q. Please state your educational background and business experience.

A. I have an MBA Degree from the University of Missouri, Kansas City and an MA Degree from the University of Northern Colorado. I have been employed by Aquila for 9 years and was previously employed as the Employee Benefits Manager at Yellow Roadway Corporation and Black and Veatch.

Q. Have you ever testified before any regulatory commission?

A. Yes, I have submitted direct and rebuttal testimony before the Kansas and Missouri commissions.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the adjustment for escalating pension plan expenses included in Pro Forma Adjustment No. 16.

Pro Forma Adjustment

Q. Please describe your supporting documents.

A. My supporting documents are for corporate-wide and Nebraska pension costs. Exhibit No._____ (PMB-1) consists of two pages of the January 1, 2006 actuarial report for the Aquila, Inc. Retirement Income Plan (Pension Plan) prepared by Aquila's actuary, Hewitt Associates (Hewitt). This is the latest actuarial report since the January 1, 2007 report will not be prepared by Hewitt until May 2007. Table 1, shown below, is the projected increase in Nebraska allocated pension expenses from 2006 to 2007. This projection was prepared by Aquila's accounting department using 2007 budget estimates provided by Hewitt. Exhibit No. ____(PMB-2) from the 2006 actuarial report shows the pension formula used to calculate benefits under the pension plan.

Q. What are the increases in pension expense?

A. Page 2 of Exhibit No.____ (PMB-1) shows the history of the FAS 87 pension annual expense increases for Aquila from $8,427,028 in 2003 to $16,146,682 in 2006. The total increase to Nebraska is the sum of the direct expense plus the allocated piece of Central Services and Corporate Services.

Table 1

NE Gas	Projected 2006	2007 Budget	Increase
Direct Cost	$1,044,504	$1,203,863	$159,359
Central Services/ Corporate	$657,730	$670,158	$12,428
Total	$1,702,234	$1,874,021	$171,787

Table 1 shows a projected increase of $159,359 in direct expense and $12,428 in allocated pension expense to Nebraska from Central Services and Corporate in 2007. Exhibit No. ____(PMB-1) also demonstrates that pension expense as a percent of compensation, a standard measure of the FAS 87 pension expense, has increased significantly greater than the inflation rate as measured by the Consumer Price Index (CPI) from 2003 through August 2006. See comparison of Aquila's pension expense increases to the CPI on Table 2 below:

Table 2

Year	Pension Expense	CPI Rate	Difference
2003	5.28%	2.27%	3.01%
2004	6.13%	2.68%	3.45%
2005	7.14%	3.39%	3.75%
2006	9.24%	3.87%	5.37%

Q. What accounts for the increase in pension expense?

A. The increase in Aquila’s pension expense is primarily the result of the annual increase in (1) the years of credited service accrued by employees and (2) annual pay increases. As years of credited service and pay increase on an annual basis, the projected expense to provide a pension benefit increases. Page 2 of Exhibit No._____ (PMB-2) shows Aquila’s pension formula. The pension benefit provided to plan participants is the amount provided by the greatest of the three formulas listed on page 52. The formula (a) results in the greatest benefit 95% of the time. That formula is 1% of final average pay (FAE) + .25% FAE – Covered Compensation (Social Security compensation) x Credited Service. Consequently, as employees earn greater service and pay, Aquila’s pension expense increases. Another major factor contributing to increased expense is the discount interest rate at which pension liabilities are valued per FAS 87 requirements. As interest rates decline, pension liabilities increase. In the last four years interest rates have declined to historic lows causing pension liabilities to increase.

Q. Does this conclude your testimony at this time?

A. Yes.

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Direct Testimony of Matthew E. Daunis

Manager, Energy Efficiency Programs
Aquila, Inc.

Energy Efficiency Programs

November, 2006

Matthew E. Daunis
20 West 9th Street
Kansas City, MO 64104
816-467-3437

Introduction

Q. Please state your name and business address.

A. My name is Matthew E. Daunis. My business address is 20 West Ninth Street, Kansas City, MO 64105.

Q. By whom are you presently employed and in what capacity?

A. I am employed as Manager of Energy Efficiency Programs for Aquila, Inc. I am testifying on behalf of Aquila, Inc. d/b/a Aquila Networks ("Aquila").

Q. What is your educational background?

A. I received a Bachelor's degree in Mechanical Engineering from the University of Maine in 1976. I received a Masters degree in Business Administration from the University of Nebraska in 1985.

Q. Please describe your professional experience.

A. I have been employed in the utility industry in positions requiring knowledge of Demand Side Management, customer service, and marketing for about 20 years. Prior to that, I was employed by a major HVAC manufacturer for ten years in various marketing and sales positions.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Aquila's proposed Demand-Side Management (DSM) programs and their costs.

Q. Please summarize your testimony.

A. In my testimony I will testify that:

1) Demand side resources should be considered on an equivalent basis to supply side resources as encouraged by the State of Nebraska, the National Association of Regulatory Commissions (NARUC) and Federal legislation and recovered through rates, and

2) Cost effectiveness should be determined by considering the impacts on the total resource costs, the utility's costs, the participant's benefits as well as potential rate impacts.

3) The program costs should be recovered through a tariff rider.

4) The programs proposed will provide a net benefit to our customers in Nebraska.

Demand and Supply Side Resources

Q. Please define supply-side and demand-side resources.

A. In general the distinction between demand-side and supply-side can be thought of as which side of the meter the resource is on. If it is on the Company's side of the meter it is supply-side. If it is on the customers' side of the meter it is demand-side. However, there is also an element of control or dispatch ability in the definitions. Both supply-side and demand-side resources can be used to meet the customer's energy needs.

Q. Has NARUC addressed demand side resources for natural gas utilities?

A. Yes. NARUC has issued two recent resolutions specifically addressing the need for energy efficiency programs for natural gas utilities. In its "Resolution on Gas and Electric Energy Efficiency" adopted by the NARUC Board of Directors on July 14, 2004 NARUC encouraged State commissions to "address regulatory incentives to address inefficient use of gas and electricity". In the same resolution they encouraged State commissions to review and consider the recommendations in the "*Joint Statement of the American Gas Association, the Natural Resources Defense Council, and the American Council for an Energy Efficient Economy*". In its "Resolution Supporting the National Action Plan on Energy Efficiency" adopted by the NARUC Board of Directors on August 2, 2006 NARUC endorses "the principal objectives and recommendations of the *National Action Plan on Energy Efficiency*, and commends to its member commissions a state-specific, and where appropriate, regional review of the elements and potential applicability of energy efficiency policy recommendations outlined in the Plan, in an effort to identify potential improvements in energy efficiency policy nationwide." The resolution cites five key elements of the *Plan*: 1) Recognize energy efficiency as a high priority energy resource; 2) Make a strong, long-term commitment to cost-effective energy efficiency as a resource; 3) Broadly communicate the benefits of and opportunities for energy efficiency; 4) Promote sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective; and 5) Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments.

Q. Does the "*Joint Statement of the American Gas Association and the Natural Resources Defense Council*" list the benefits of natural gas energy efficiency programs?

A. Yes. The statement lists several benefits:

- Customers could save money by using less natural gas
- Reduced overall use would help push down short-term prices at times when markets are under stress, reducing costs for all customers (whether or not they participate in utility energy efficiency programs)
- State policies to encourage economic development would be enhanced by increased energy efficiency and lower business energy costs
- State regulatory commissions would be able to support larger state policy objectives

Q. Does the Energy Policy Act of 2005 address demand side resources?

A. Yes. Section 139 of the Act directs the Secretary of Energy, in association with NARUC and the state energy offices, to study the impact of state policies that encourage energy efficiency including:

(1) performance standards for achieving energy use and demand reduction targets;

(2) funding sources, including rate surcharges;

(3) infrastructure planning approaches (including energy efficiency programs) and infrastructure improvements;

(4) the costs and benefits of consumer education programs conducted by State and local governments and local utilities to increase consumer awareness of energy efficiency technologies

and measures; and

(5) methods of—

(A) removing disincentives for utilities to implement energy efficiency programs;

(B) encouraging utilities to undertake voluntary energy efficiency programs; and

(C) ensuring appropriate returns on energy efficiency programs.

Further, Section 123(b) states that each state's energy efficiency plan should have a goal of achieving a 25% improvement in the efficiency of energy use by 2012 over a 1990 baseline.

Q. Has the State of Nebraska recognized the value of energy efficiency?

A. Yes. There are many instances where the citizens and the government of the State have recognized the value of energy efficiency. Two recent instances are particularly worthy of note. First, in August of 2006 several organizations formed the Nebraska Energy Alliance. The formation of this organization was reported to the Commission at its August 15th public meeting. The organization's mission is "to assist Nebraskans meet energy needs through education, collaboration and advocacy".

Q. What organizations are represented on the Nebraska Energy Alliance?

A. The breadth of organizations supporting this initiative underscores the recognition of the value of energy efficiency. The founding general members of the Alliance include:

- American Red Cross Heartland Chapter
- Aquila, Inc.
- Dawson Public Power District
- Kinder Morgan
- Loup Public Power District
- Nebraska Public Power District
- Northwestern Public Service
- Omaha Public Power District
- The Salvation Army

The founding advisory members include:

- Nebraska Public Service Commission
- Nebraska Health and Human Services
- Nebraska Energy Office

Q. Is there another instance where the State of Nebraska has recognized the value of energy efficiency?

A. Yes. The 98th Legislature enacted Legislative Bill 888, that adopted the 2003 International Energy Conservation Code. The legislation indicates that the

Legislature adopted this code because it found that the increased energy efficiency has benefits for the State including: increased energy savings for all Nebraska consumers, a reduction in the cost of imported energy and a reduction in the growth of energy consumption.

Q. Do you conclude that demand side resources are an accepted and appropriate component of Aquila's resource portfolio, consistent with the objectives of the NARUC resolutions and the Energy Policy Act of 2005?

A. Yes.

Cost Effectiveness

Q. How is cost effectiveness determined?

A. A program is cost effective if the benefits from the program exceed the costs of the program. There are four commonly used perspectives upon which to measure these costs and benefits: 1) The Total Resource Cost perspective compares the total costs of the program, including the costs of the energy efficiency measures and the program administrative costs, to the total benefits of the program, principally the avoided natural gas purchase costs. 2) The Utility Resource Cost perspective compares just those costs incurred by the utility, incentives and administrative costs, to the avoided costs. 3) The Participant Cost perspective compares the costs incurred by the participant, the measure costs net of any utility incentives, to the reduction in the participants' bills. 4) The

Rate Impact perspective compares the costs of the program, including the measure costs, administrative costs and the reduction in revenues due to reduced sales associated with the program to the avoided costs. Exhibit ______(MED-1) is a table that illustrates these tests.

Q. Which test best compares the demand side programs on a consistent basis with supply side resources?

A. The Total Resource Cost test compares demand side and supply side most consistently. As an illustration, let's consider the requirements to meet a new demand. That requirement would consist of the purchase of additional gas supplies and potentially upgrades to the infrastructure. The costs of these purchases and infrastructure upgrades would be born by the utilities customers in their entirety through the pass-through of the purchase costs and the rate recovery of the infrastructure upgrades. Similarly, the costs of energy efficiency measures and the administrative costs of the programs would be born by the customers in their entirety. In the case of energy efficiency measures the costs associated with program administration and utility incentives would be recovered in rates. The remaining costs would be born by the program participants directly, through their purchase of the energy efficiency measures net of any incentives provided by the program. Thus, the Total Resource Cost best compares the supply side approach to the demand side approach to meeting the increased energy demand. If the program passes the Total Resource Cost test, then the overall costs of supplying the demand are less with the demand side program than with a supply side option.

Q. What about the rate impacts of demand side resources?

A. A program that passes the Total Resource Cost test, by definition, reduces the overall costs of supplying natural gas to meet the needs of customers. It is sometimes argued that a program must pass the Rate Impact test in order to be considered cost effective. Let me explain why I believe that such an approach is not in the customers' interest. The Rate Impact or No-Losers test has also been called the "hardly anybody wins" test. A simple analysis can illustrate why. Suppose a utility has a load of 100 therms, a revenue requirement of $115 and it has to meet a 1 therm increase in load. It can do so either through conservation or buying additional gas. A 1 therm conservation measure that costs nothing would leave rates unchanged. Any conservation that costs more than nothing will raise rates. A natural gas purchase that costs $1.15 per therm would also leave rates unchanged. Thus, any purchase that costs less than $1.15 per therm would lower rates. To adhere to the no-losers test, a utility would have to eschew ***zero cost*** conservation to pursue all natural gas up to $1.15 per therm. Clearly this outcome makes no economic sense and discourages investments in cost-effective conservation.

Proposed Programs

Q. What programs are being proposed by Aquila?

A. While Aquila has comprehensive program portfolios in other jurisdictions, it is proposing a modest initiation of programs in Nebraska. The programs include:

- Space and Water Heating Equipment Rebates
- Low-Income Weatherization

Exhibit _______(MED-2) presents a description of the programs including their costs, expected savings and cost effectiveness analysis.

Q. How did Aquila choose these programs?

A. These programs will meet the needs of a broad range of customers, capture savings opportunities that would otherwise be lost if customers install standard efficiency space and water heating equipment, and provide assistance to the most vulnerable energy consumers. These program efforts will help to establish an infrastructure for an expanded portfolio of programs by working with local trade allies and delivery partners including heating contractors, builders, and local agencies.

Q. Are these programs cost effective?

A. Yes. The programs are cost-effective from the Total Resource Cost perspective, the Utility Cost perspective and the Participant perspectives.

Cost Recovery

Q. How will the DSM program costs be recovered?

A. The Company is suggesting that a Energy Efficiency Tariff Rider approach be used to recover the costs of demand side programs.

Q. Why is a specific cost recovery mechanism necessary for demand side resources?

A. Demand side resources are purchased in small increments, rarely large enough to warrant specific rate filings. This is unlike supply side resources that are flowed through to the customer at the time they are incurred. Consequently, other mechanisms are necessary for the cost recovery of demand side resources. These mechanisms generally fall into one of two categories. The first category is deferral and amortization. Under this mechanism the costs are accumulated in a balance sheet account and deferred over a period of time. The balance on the balance sheet becomes part of the rate base upon which the Company earns its authorized return. The balance is amortized over a specified period of time and recovered in rates. The asset that supports the balance sheet entry is not, however, tangible. It is a regulatory asset. The physical asset that was purchased through the demand side programs resides in multiple customer locations and is not “owned” by the Company. Consequently, a second approach has been adopted in several jurisdictions. This approach matches a surcharge or tariff rider with the annual expenditures. Expenditures accumulate in a balancing account and are offset by the collections from the tariff rider. The level of the funding mechanism is adjusted on a regular basis to maintain a balance in the balancing account that is near zero.

Q. Please explain.

A. The Energy Efficiency Tariff Rider approach would recover the DSM program costs through a line item charge. For energy efficiency the Tariff Rider is set at a particular dollar level determined by the expected cost of the DSM programs identified for the year following the institution of the Tariff Rider.

Q. At what level are you proposing to set the Tariff Rider?

A. The total of the first year of energy efficiency expenditures to fully implement the programs is $631,050 ramping up to $1,152,875 in the third-year at full implementation levels. The Company proposes that the initial Tariff Rider be set at approximately $850,000 for energy efficiency programs including low income weatherization to recognize that there is a ramp up period during the first year of implementation. Setting the level somewhat higher than the first year expected costs will allow the surcharge rate to remain unchanged in the second year. This surcharge would be approximately $0.0070/Therm or 0.6% of the current natural gas price. For an average residential customer, the surcharge would be approximately $0.40 per month or less than $5.00 per year.

Q. How would the funds collected by the Tariff Rider be accounted for?

A. The funds collected would be accounted for in a balancing account. This would assure that any amounts not spent in a given year would carry forward to the following year. Similarly, if the amounts spent exceed the amounts collected for energy efficiency in a given year the deficit would be recovered in the following year. The Company would report the level of the balancing account to the Commission annually. Adjustments to the Tariff Rider will be proposed in order to closely match the actual Tariff Rider collections with the expected DSM expenditures.

Q. Does this conclude your direct testimony?

A. Yes.

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Direct Testimony of Glenn W. Dee

State Regulatory Manager

Working Capital and Pro-Forma Adjustments

November 1, 2006

Glenn W. Dee
1815 Capitol Avenue
Omaha, NE 68102
402-221-2020

Introduction

Q. Please state your name, position, and business address.

A. My name is Glenn W. Dee. I am State Regulatory Manager for Aquila Networks ("Aquila"). My business address is 1815 Capitol Avenue, Omaha, Nebraska, 68102.

Q. What is your educational background and work experience?

A. I received a Bachelor of Arts in Business Administration, with a concentration in Accounting from Clark College, Atlanta, Georgia, in 1971. I received my Masters of Business Administration degree from the University of Nebraska at Omaha in 1975. Subsequently, I have completed requirements for and received a Certificate in Management Accounting (CMA) issued by the National Association of Accountants. I also have received a Nebraska Certified Public Accountant certificate. I began my employment with Aquila in June of 1972. At that time Aquila was known as Peoples Natural Gas. While employed with Aquila, I have held numerous accounting and accounting-related positions such as Auditor, Supervisor of Disbursement Accounting, Supervisor of General Accounting, Director of Operational Planning, and Director of Property and Disbursement Accounting. I joined Aquila's Regulatory Department in May, 1984 and became State Regulatory Manager for Colorado and Nebraska in June 2000. Additional related experience includes preparing financial rate case information for and testifying before the Minnesota Public Utilities Commissions, Colorado Public Utilities Commission, and the Iowa Utilities Board. I have also served as a rate consultant for the cities of Tallahassee, Florida and Safford, Arizona.

Q. What are your principle duties in your present position?

A. I am the State Regulatory Manager for Aquila's Nebraska operations. In this position, I am responsible for, among other things, providing management with rate information for Nebraska. As such, I participate in the preparation of rate-of-return, cost of service, rate design and other rate related studies and filings for Nebraska. I also direct the preparation of financial exhibits and other information for regulatory filings with the various state commissions and local jurisdictions.

Q. What is the purpose of your Testimony?

A. In my testimony, I will (a) address the filing requirements for a General Rate filing required by the State Natural Gas Regulation Act and Nebraska Public Service Commission Regulations, (b) explain how Working Capital was computed, and (c) serve as Aquila's sponsor for three pro-forma adjustments.

FILING REQUIREMENTS

Q. Explain the filing requirements and how the Financial Exhibits are organized.

A. The State Natural Gas Regulation Act, enacted as Nebraska Revised Statutes sections 66 -1801 to 66-1857 (2003), (Act") along with Chapter 9, Rule 004 of the Commission's Rules and Regulations require that Aquila include certain financial information in any general rate filing. Accordingly my testimony will explain and support these required financial schedules. My testimony will also support several proposed adjustments to the Base Year, and the Working Capital Computation used in Aquila's filing.

Q. What do the Act and Commission Regulation require Aquila to file in support of its request for an increase in natural gas rates?

A. The Nebraska Public Service Commission issued Rule and Regulation No. 157 on June 25, 2003, and subsequently revised and amended the Rules and Regulations on November 4, 2003 and again on June 13, 2006. The Commission's Rules and Regulations require several documents to be filed. For example, Rule 004.01 of the Commission's rules and regulations requires Aquila to include; eight copies of the most recent annual report to stockholders, and eight copies, plus an electronic copy of the following information, verified by a statement under oath by an officer. Other subparts of that rule require the following items: (1) A description of the base year and test year; (2) A financial summary showing aggregate amounts for rate base, operating revenue, operating expenses, and rate of return for the base year and test year using natural gas rates currently in effect and using proposed natural gas rates; (3) Rate Base schedules showing beginning and ending balances for the base year and test year of utility plant and accumulated depreciation and amortization showing the balance by functional account totals; (4) Working Capital, showing the manner in which it is calculated; (5) Allocated rate base components showing the manner in which the components are calculated; (6) Operating expense schedules for the base year and test year, rate of return and cost-of-capital schedules; (7) Operating revenue schedules showing number and classification of customers, volume of sales, and operating revenue by customer classes for the base year on an unadjusted basis and for the test year on a normalized basis, using current and proposed rates.

Q. Does your filing comply with the Act and the Commission's Rules and Regulations?

A. Yes. All of the documents or explanations required by the Act and the Commission's Rules and Regulations can be found in the Application behind the following tabs: "Financial", "Base Year", "Test Year", "Test Year Proposed", "Adjustments", "Class Cost of Service Study", and "Working Capital". The tabs are color coded. The red tabs contain the financial information specific to Rate Area One, the blue tabs contain the financial information specific to Rate Area Two, and the green tabs contain the financial information specific to Rate Area Three. The white tabs contain information common to all Rate Areas and includes the “Filing Application,” “Definitions and General Information,” “Adjustments,” “Class Cost of Service Study,” “Working Capital,” “Proposed Rate Schedules.” “Current Rate Schedules,” and “2005 Annual Report.”

Q. What information can be found in each of the sections?

A. The “Financial” section (Exhibit I) summarizes the revenue deficiency computation. The “Base Year” section (Exhibit II) provides unadjusted financial data from the company’s books and records for the twelve-month period ending June 30, 2006. The “Test Year” section (Exhibit III) provides financial information showing known and measurable adjustments made to the Base Year. The “Test Year Proposed” (Exhibit IV) summarizes the allocation of the proposed revenue increase among customer classes and the proposed rates. The “Adjustments” section (Exhibit V) details all pro forma adjustments applied to the Base Year. The “Class Cost of Service Study section (Exhibit VI) summarizes the cost allocation procedures used to allocate indirect cost to the various customer classes. The Working Capital section (VII), explains more thoroughly how Cash Working Capital was computed.

Q. Please explain the difference between the base year and the test year?

A. The base year is the twelve months ending June 30, 2006, reflecting actual financial performance as recorded in the financial books and records. The test year was derived by taking the base year and adjusting it for known and measurable changes, as well as applying a normalization adjustment, as required by the Act, and an annualized adjustment to correct for out-of-period billing entries.

WORKING CAPITAL

Q. **Please explain how Working Capital was computed**.

A. Working Capital is a component of Rate Base and can be found on Schedule B, of Exhibits II, and III. Working Capital is comprised of prudent inventories of materials and supplies, including gas storage inventories, prepayments and a cash working capital component. An adjustment is made reducing working capital for Accumulated Reserve for Deferred Income Taxes, Contributions in Aid of Construction, Rate Payer Deposits, and Customer Advances.

Q. How was Cash Working Capital computed?

A. Aquila uses the Lead/Lag Methodology (also referred to as a lead-lag study) in computing Cash Working Capital. The Lead/Lag Methodology measures the amount of cash working capital needed by looking at the timing difference between when cash comes in and when it is disbursed for various expenses. The actual computation is explained more fully in the tab labeled "Working Capital".

ADJUSTMENTS

Q. What Adjustments are you sponsoring?

A. I am sponsoring Adjustment #3, the Lincoln Lateral Adjustment; Adjustment #5, Gas Storage Adjustment; Adjustment #8, Rate Case Expense; and Adjustment #13, Bad Debt Expense.

Q. What is the Lincoln Lateral?

A. Minnegasco, Inc. (Minnegasco) was the prior owner of Aquila's gas distribution system located in Lincoln, Nebraska. In 1989, the City of

Lincoln and Minnegasco reached an agreement called a "Memorandum of Understanding", to build an intrastate pipeline connecting Natural Gas Pipeline Company's (NGPL's) interstate natural gas transportation line to Minnegasco's local distribution system serving the city of Lincoln. The intrastate pipeline was referred to as the "Lincoln Lateral Pipeline Project" or "Lincoln Lateral". The purpose for constructing the Lincoln Lateral was to provide competition for transportation and other related services from interstate pipelines serving the local distribution system serving Lincoln, and to provide access to alternate supply sources of natural gas. Prior to the time of construction of the Lincoln Lateral off, Northern Natural Gas Company was the only interstate natural gas pipeline from which supplies could be obtained for the local distribution system serving Lincoln.

Q. How was the cost of the Lincoln Lateral to be recovered?

A. Pursuant to the Memorandum of Understanding (MOA), for the first five (5) years the cost for transportation service for system supply through the Lincoln Lateral would be considered as an element of the cost of supplying natural gas and passed through to customers pursuant to the Purchase Gas Adjustment mechanism ("PGA"). The MOA further provided that after the initial five years, Minnegasco "may" include the same Lincoln Lateral costs in base rates, instead of the PGA.

Q. How is Aquila proposing handling the Lincoln Lateral in this Rate Filing?

A. Aquila purchased Minnegasco Nebraska distribution assets in 1993. As a successor-in-interest to Minnegasco, Aquila has operated the Lincoln Lateral as a separate entity, and did not roll the costs into its general rates. However, in this general rate filing, Aquila is proposing to merge the Lincoln Lateral Pipeline and associated cost with the rest of the Aquila Nebraska operations as allowed by the Memorandum of Understanding.

Q. How does this proposal affect the rate setting process?

A. The impact of including the Lincoln Lateral in general rates is minimal, and should benefit Lincoln customers. The Net Plant and O&M expense previously associated with the Lincoln Lateral and recovered through the PGA, will now be included with the Plant and O&M attributable to Rate Area II and be recovered through the margin.

Q How will this proposed merger benefit the customers in the City of Lincoln.

A. The merger has the potential of benefiting the Lincoln customers in several ways: (1) The current Rate of Return guaranteed by the Memorandum of Understanding is 11.97%. To any extent Aquila's Rate of Return on Rate Base is less than 11.97% the Lincoln customers will benefit, (2) The cost associated with natural gas will go down, to the extent that the operating cost of the Lincoln Lateral will no longer be automatically passed through the PGA, (3) Previously, all projected incremental transportation volume revenues were to be shared with the City of Lincoln on a 50-50 basis credited against the PGA. Now, 100 percent of the jurisdictional incremental transportation volume revenues will be included in the Rate Area II revenue requirement computation, and (4), any cost incurred by the city to review the annual reports required by the Memorandum of Understanding will no longer occur.

Q. What is the Bad Debt Expense Adjustment?

A. In November 2005, the Nebraska Public Service Commission granted Aquila Application NG-004.1 to recover the gas cost portion of Aquila's uncollectible account expense through the PGA mechanism. In that Commission proceeding, Aquila stated that it would remove the bad debt related to gas costs from its rates in its next general rate filing. The Bad Debt Expense Adjustment proposed in this case removes the gas cost from uncollectible account expense (i.e., bad debt for gas costs), thereby reducing O&M and the distribution margin.

Q. What is Gas in Storage?

A. Unlike electricity, natural gas can be stored to be withdrawn as needed. Natural gas may be stored in a number of different ways. It is most commonly held in inventory underground under pressure.

Q. Why is Gas in Storage important to serve Aquila customers?

A. One use of storage fields is as a winter supply source. Gas is typically injected in the summer months and withdrawn in the winter months. This process also provides a more level usage profile for well production, as a place to put the gas in the summer when usage is down. In the past several years, storage gas has provided the cheapest supply of gas in the winter months.

Q. How do you determine the cost of Gas in Storage at December 31, 2006?

A. Our plan calls for our storage to be essentially filled by October 31, 2006 with periodic purchases of gas. We started from the July 31, 2006 estimated balances. We estimated the December 31, 2006 balance by reflecting the planned injection volumes for August, September and October using the August monthly index prices and

September/October price estimates from Nymex pricing. We also reflected the planned withdrawals for November and December.

Q. Besides winter supply, do storage fields have other benefits?

A. Yes, storage allows pipelines, LDC's and end users to balance daily and monthly load fluctuations. Aquila's contracts for storage, also helps meet our operational needs. Aquila's load fluctuates daily based on many factors. From September to May, weather plays a major role in creating load swings. Pipelines require Aquila to deliver a similar amount of gas compared to what we consume. If we do not deliver the proper amounts, we incur significant penalties or scheduling charges.

Q. What Adjustment is Aquila proposing to account for Rate Case Expense?

A. Aquila estimated that the total cost of completing the rate case in the three rate areas would be $500,000. This estimated cost would cover legal representation, outside consultants, filing fees, and miscellaneous out-of-pocket expenses. Historically, Aquila has been on a three year cycle for filing rate cases in the state of Nebraska. For that reason only one third of the cost was included in Operations and Maintenance Expense (O&M). Normally Aquila would include the remaining two thirds in rate base, but under the premise advocated by the consultants in previous Aquila Nebraska rate cases, Aquila has only included one third of the unamortized portion. The premise being, that if Aquila files a rate case every three years, then Aquila would be over earning on the unamortized amount if two thirds were included in rate base for two years. The inclusion of one third in rate base resolves the issue of over earning on unamortized rate case expense.

Proposed Tariff Sheets

Q. Has Aquila filed proposed tariffs in this proceeding?

A. Yes, in compliance with the Act, Aquila has filed proposed tariffs in this proceeding. Aquila has filed proposed tariff to reflect the new customer charges and commodity margins shown in Index No. 13 and mentioned in Mr. Sullivan's testimony. In addition, Aquila is proposing changes to the Purchase Gas Cost Adjustment, Aquila's Deposit Policy, Billing and Payment Policy, Energy Diversion Policy, and Cold Weather Rule.

Q. What changes is Aquila proposing to the Purchase Gas Cost Adjustment Tariff – Index No. 8?

A. Aquila is proposing changing the month of the reconciliation year-end from August 31st to June 30th. The August 31st date does not give Aquila enough time to prepare the Annual Gas Cost Reconciliation, which is due to the Commission on or before October 1st of each year.

Q. What changes is Aquila proposing to the Deposit Policy – Index No. 22?

A. Aquila is changing the amount of deposit to be collected from "one month's highest energy bill in the previous twelve-month period" to "one-sixth of the estimated annual bill". Also, the definition of "credit risk" has been expanded. Both of these changes are in compliance with the Commission new rules.

Q. What changes is Aquila proposing to the Billing and Payment Policy – Index No. 23?

A. Aquila is removing some archaic wording from the Streamline Plan which specifies a uniform amount for eleven (11) months with the twelfth (12) month (July) being the month to balance the account. By removing this language Aquila will be able to adjust the Streamline Plan for unusual and unexpected changes in gas cost.

Q. What changes is Aquila proposing to the Energy Diversion Policy – Index No. 24?

A. The current tariff requires Aquila to give the customer ten days notice prior to disconnecting any illegally attached device to Aquila's property. Aquila recognizes that any device not installed by Aquila or an Aquila qualified technician, not only represents a theft of service, but may create an unsafe and potentially dangerous environment for the customer and surrounding neighbors. Aquila's changes remove the ten (10) day notice requirement, and explain the charges for this illegal action.

Q. What changes is Aquila proposing to the Cold Weather Rule – Index No. 32?

A. Aquila is making several changes to the Cold Weather Rule Tariff including (1) eliminating the wording specifying no disconnection would take place when the local national weather service office forecasts the temperature will drop below 30 degrees, (2) Changed the wording of the arrearage and current payments to match that of the Commission Rules, and (3) adding the statement that no residential customer certified as eligible for low income energy assistance and has communicated such eligibility to the Company will be disconnected during the cold weather period. These changes and others will make Aquila's Cold Weather Rule more in line with the Commission's Rule.

Q. Are there any other proposed tariffs you are sponsoring?

A. Yes, the General Index, Superceded Index, and the General Rules and Regulation Index. These are index No. 1, Index No. 2, and Index No. 20 respectively. Changes in these indices merely reflect the updates Aquila proposes in the tariff sheets.

Q. Has Aquila included a Legislative or Red-Lined version of the proposed changes to its Tariffs, Rules and Regulations?

A. Yes, Aquila has included a Red-Lined version of the proposed changes to its Tariffs, Rules and Regulations.

Q. Does this conclude your pre-filed direct testimony?

A. Yes it does.

BEFORE THE NEBRASKA PUBLIC SERVICE COMMISSION

In the matter of Aquila, Inc.)	
d/b/a Aquila Networks ("Aquila"))	Docket No. NG-xxxx
seeking a general rate increase)	Docket No. NG-xxxx
for Aquila's Rate Areas One, Two)	Docket No. NG-xxxx
and Three (not consolidated))	

Direct Testimony of Ruth H. Gustin

Manager, Employee Benefits

Health Care Expense

November, 2006

Ruth H. Gustin
20 West 9th Street
Kansas City, MO 64104
816-467-3914

Introduction

Q. Please state your name and business address.

A. My name is Ruth H. Gustin, and my business address is 20 W. 9th Street, Kansas City, MO 64105.

Q. By whom are you employed and in what capacity?

A. I am employed by Aquila, Inc. as Employee Benefits Manager. In that capacity, I am responsible for managing the day-to-day administration of Aquila's employee benefit plans.

Q. Please state your educational background and business experience.

A. Certified Employee Benefits Specialist. I have been employed by Aquila for 8 years. Previously, I was the Director of Human Resources at H&R Block.

Q. Have you ever testified before any regulatory commission?

A. Yes, I submitted direct testimony before the Kansas Corporation Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the adjustment for escalating health care expenses included in Pro Forma Adjustment No. 16.

Pro Forma Adjustment No. 16

Q. Please describe your supporting documents.

A. Adjustment No. 16 is the allocated cost of providing medical coverage to Nebraska employees. My supporting documents are for corporate-wide health care costs. Exhibit No._____(RHG-1) is the projected increase in medical insurance premiums for 2007. This estimate comes from Pricewaterhouse Coopers LLP. and is based on actual claims paid for the twelve months ending June 30, 2006. Exhibit No. _____(RHG-2) shows the history of medical cost increases and is taken from Hewitt's "Health Care Expectations: Future Strategy and Direction 2006." Exhibit No. _____(RHG-3) is taken from a September 2005 press release which summarizes the results of the 2006 Towers Perrin Health Care Cost Survey. Exhibit Nos. ____(RHG- 2) and _____(RHG-3) demonstrate the reasonableness of the trend factor used to calculate Aquila's 2007 medical premium equivalents.

Q. Is medical insurance the only component of this adjustment?

A. No, in addition to the medical insurance premiums, there is the dental plan and vision plan. These are minor compared to the medical insurance component, and their annual increases have been projected for budgeting purposes. Mr. Richard Petersen will address the impact of all health care increases on Nebraska operations.

Q. How fast are health care costs rising?

A. Aquila's overall medical plan rate increase for active employees in 2007 will be 14.8%, as shown on Exhibit No. ______ (RGH –1)

Q. **What accounts for this rapid increase in health care costs?**

A. The average age of active Aquila employees is 45. As employees age, their physical health tends to decline requiring greater medical and Rx services. Additionally, medical inflation exceeds the general inflation rate and new technology and other factors have increased the cost of services.

Q. **What has Aquila done to control health care costs?**

A. Aquila's medical cost increases for the five years prior to 2007 averaged under 10% per year, while the national average for similar preferred provider plans was up to 8.2% higher. Aquila has continued to control costs by negotiating lower discounts with its health care provider networks, including renegotiating prescription plan rates through the employer coalition that Aquila joined in 2005, introducing and continuing to promote a "consumer directed" health plan option designed to give employees more involvement in management of their health care dollars, and continuing to emphasize the importance of health management and lifestyle changes through the HealthyPath program. HealthyPath is a program initiated in 2004 that offers health risk assessments, personal health nurse coaches, weight control assistance, fitness and other health-related programs. These offerings are complimented by online tools that employees can use to make better decisions about their utilization of health care services. Because health status and health care consumerism are only two factors that affect medical costs, we expect medical cost increases to continue to rise in spite of these efforts.

Q. Are health care costs expected to decline in the foreseeable future?

A. No, as the population in general ages and requires greater health care services demand for medical services will continue to increase; in addition, medical inflation is expected to increase due to new technologies and other factors. Aquila’s objective in offering HealthyPath and the consumer-directed health plan model is to engage employees in helping to reduce the trend of medical cost inflation for the company. Aquila will also continue to seek ways to limit future cost increases by managing administrative costs of operating the plans and promoting utilization of medical providers and medical care that offer the best quality and cost value to participants.

Q. Does this conclude your testimony at this time?

A. Yes.

BEFORE THE NEBRASKA PUBLIC SERVICE COMMISSION

In the Matter of Aquila, Inc.,	)	
d/b/a Aquila Networks (“Aquila”)	)	
seeking a general rate increase	)	Docket No.
for Aquila’s Rate Areas One, Two	)	
and Three (not consolidated)	)	

Direct Testimony of Donald A. Murry, Ph.D.

Vice President
C.H. Guernsey & Company

Cost of Capital

October, 2006

Donald A. Murry
5555 N. Grand Blvd.
Oklahoma City, OK 73112
405-416-8100

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DIRECT TESTIMONY OF

DONALD A. MURRY

<u>POSITION AND QUALIFICATIONS</u>

Q. PLEASE STATE YOUR NAME.

A. My name is Donald A. Murry.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am a Vice President and economist with C. H. Guernsey & Company. I work out of the Oklahoma City office and the Tallahassee office. I am also a Professor Emeritus of Economics on the faculty of the University of Oklahoma.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I have a B. S. in Business Administration, and a M.A. and a Ph.D. in Economics from the University of Missouri - Columbia.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A. From 1964 to 1974, I was an Assistant and Associate Professor and Director of Research on the faculty of the University of Missouri - St. Louis. For the period 1974-98, I was a Professor of Economics at the University of Oklahoma, and since 1998 I have been Professor Emeritus at the University of Oklahoma. Until 1978, I also served as Director of the University of Oklahoma's Center for Economic and Management Research. In each of these positions, I directed and performed academic and applied research projects related to energy and regulatory policy. During this time, I also served on several state and national committees associated with energy policy and regulatory matters, published and presented a number of papers in the field of regulatory economics in the energy industries.

Q. WHAT IS YOUR EXPERIENCE IN REGULATORY MATTERS?

A. I have consulted for private and public utilities, state and federal agencies, and other industrial clients regarding energy economics and finance and other regulatory matters in the United States, Canada**,** and other countries. In 1971-72, I served as Chief of the Economic Studies Division, Office of Economics of the Federal Power Commission. From 1978 to early 1981, I was Vice President and Corporate Economist for Stone & Webster Management Consultants, Inc. I am now a Vice President with C. H. Guernsey & Company. In all of these positions I have directed and performed a wide variety of applied research projects and conducted other projects related to regulatory matters. I have assisted both private and public companies and government officials in areas related to the regulatory, financial**,** and competitive issues associated with the restructuring of the utility industry in the United States and other countries.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE OR BEEN AN EXPERT WITNESS IN PROCEEDINGS BEFORE REGULATORY BODIES?

A. Yes, I have appeared before the U.S. District Court-Western District of Louisiana, U.S. District Court-Western District of Oklahoma, District Court-Fourth Judicial District of Texas, U.S. Senate Select Committee on Small Business, Federal Power Commission, Federal Energy Regulatory Commission, Interstate Commerce Commission, Alabama Public Service Commission, Alaska Public Utilities Commission, Arkansas Public Service Commission, Colorado Public Utilities Commission, Florida Public Service Commission, Georgia Public Service Commission, Illinois Commerce Commission, Iowa Commerce Commission, Kansas Corporation Commission, Kentucky Public Service Commission, Louisiana Public Service Commission, Maryland Public Service Commission, Mississippi Public Service Commission, Missouri Public Service

Commission, Nebraska Public Service Commission, New Mexico Public Service Commission, New York Public Service Commission, Power Authority of the State of New York, Nevada Public Service Commission, North Carolina Utilities Commission, Oklahoma Corporation Commission, South Carolina Public Service Commission, Tennessee Public Service Commission, Tennessee Regulatory Authority, The Public Utility Commission of Texas, the Railroad Commission of Texas, the State Corporation Commission of Virginia, and the Public Service Commission of Wyoming.

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A. Aquila, Inc. ("Aquila, Inc.") retained me to analyze the current cost of capital and recommend a rate of return and capital structure that is appropriate for the Aquila Networks – Nebraska, a division of Aquila, Inc. In this testimony, I will also refer to Aquila Networks – Nebraska, as "Aquila" or the "Company" in this proceeding.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I am sponsoring an exhibit that I have attached to my testimony which includes Schedules DAM-1 through DAM-28.

Q. WAS THIS EXHIBIT PREPARED EITHER BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, it was.

SUMMARY OF TESTIMONY

Q. CAN YOU SUMMARIZE YOUR ANALYSIS AND TESTIMONY IN THIS CASE?

A. First, I studied the current economic environment, taking note especially of the recent economic expansion and the accompanying inflationary pressures. This environment, in turn, has caused the Federal Reserve to repeatedly raise interest rates, with the direct consequence of increasing utility capital costs generally. Moreover, this environment has created an atmosphere of anticipated, continued interest rate increases according to consensus forecasts.

For my analysis of the cost of capital of Aquila Networks - Nebraska, I considered the appropriate capital structure, the cost of debt, and the cost of common stock, and in the analysis of each of these factors the restructuring of Aquila, Inc., I identified a group of LDCs that provided a basis for analyzing the cost of capital of an LDC similar to Aquila Networks - Nebraska. For example, in my determination of the appropriate capital structure for ratemaking in this proceeding, I noted that the Aquila Networks - Nebraska divisional capital structure, which has a lower common stock equity ratio than the average of the group of LDCs that I studied, was appropriate. This is the permanent capital supporting Aquila's assets that provide the gas distribution service to the Nebraska customers. The appropriate cost of debt for this proceeding is the embedded cost of long-term debt of Aquila of 7.13 percent.

For the measurement of common stock equity of Aquila, I also relied extensively upon the measured costs of common equity of the comparable companies. The common, market-based Discounted Cash Flow ("DCF") method and Capital Asset Pricing Model ("CAPM") were useful for estimating the cost of the comparable utilities. I could not use the DCF to analyze the cost of common for Aquila, Inc. because of the recent history of negative earnings, no dividends and no forecasted dividends. I also reviewed the financial statistics of Aquila, Inc. and the comparable LDCs. Additionally, I noted that *Value Line* is predicting that the comparable companies will earn an average return on common stock in 2006 of 11.8 percent. *Value Line* also is predicting that the gas distribution sector will earn 12.0 percent on common stock equity in the period 2009 to 2011. As a comparison, *Value Line* predicts that Aquila, Inc. will again experience a loss in 2006 and for the fourth year will not pay a dividend.

To interpret the DCF and CAPM analyses, I also evaluated several specific business risk factors of Aquila Networks - Nebraska. Taking these risk factors into account I determined a recommended allowed return for Aquila in this proceeding. I am recommending an allowed return for the Company in this proceeding in the range of 11.75 to 12.25 percent, but I think that realistically the midpoint of this range, or 12.0 percent, is the minimal level necessary for Aquila to maintain an acceptable probability of acquiring capital. This common equity return results in a recommended return on total capital ranging between 9.60 percent and 9.73 percent.

I tested my recommended return to verify that it was sufficient to attract and maintain capable, and at the same time, to determine that my recommendation would not produce an excessive return to common stock holders. As a straight-forward measure, I compared the After-Tax Interest Coverage for Aquila at the higher end of my recommended return level is 2.77 times. This is much lower than the average coverage for the comparable utilities, which is 3.62 times, and lower than the coverage for all but one of the comparable utilities. From this comparison, it is apparent that my recommended allowed return for Aquila is conservative in current markets.

<u>UTILITY REGULATION</u>

Q. DID THE POLICIES AND PROCEDURES OF UTILITY REGULATION AFFECT YOUR COST OF CAPITAL TESTIMONY IN ANY WAY?

A. Yes. I based my analysis and recommendations on my interpretation of the role of regulation in the natural gas distribution industry. Because of the nature of the industry, analysts have recognized the likely presence of market power in a franchised utility market. Economies of scale at the distribution or retail level of utility service indicate that the duplication of facilities by more than one firm may be economically inefficient. This is the principal economic rationale for utility regulation, and I used this as a guide for my analysis and recommendations in this proceeding. Consequently, I predicated my analysis on the objective to set an allowed return in a regulatory proceeding that is sufficient to allow a utility to recover the costs of providing service, but not higher than necessary to attract and maintain invested capital that provides utility service. As an economist, I believe that these analytical objectives are consistent with the legal standard of a "fair rate of return" in regulation.

Q. WHAT DID YOU MEAN WHEN YOU MENTIONED THE "LEGAL STANDARD" THAT YOU USED TO MEASURE A "FAIR RATE OF RETURN?"

A. I am using the term "fair rate of return" in a manner that is consistent with my understanding of the return that meets the standards set by the United States Supreme Court decision in *Bluefield Water Works and Improvement Company vs. Public Service Commission, 262 U.S. 679 (1923) ("Bluefield")*, as further modified in *Federal Power Commission vs. Hope Natural Gas Company, 320 U.S. 591 (1944) ("Hope").* As I understand these decisions, they characterize a "fair rate of return" as one that provides earnings to investors similar to returns on alternative investments in companies of equivalent risk.

Q. AS AN ECONOMIST, WHAT IS YOUR INTERPRETATION OF THE TERM A "FAIR RATE OF RETURN"?

A. As I understand it, the term a "fair rate of return" means that a return is sufficient to enable a company to operate successfully, maintain its financial integrity, attract capital on reasonable terms, and compensate investors for the risks associated with the provision of natural gas service. Throughout my analysis, I was very sensitive to both the financial and business risks of Aquila in providing gas distribution service in Nebraska.

ECONOMIC ENVIRONMENT

Q. WHAT DID YOU DETERMINE ARE THE CURRENT ECONOMIC FACTORS THAT ARE IMPORTANT FOR SETTING THE COST OF CAPITAL IN THIS PROCEEDING?

A. The key factors in the current economic environment that affect investors are expectations regarding inflation and interest rates. Forecasts of inflation and interest rates affect investors' expectations of returns and their evaluations of the risks and returns on alternative investments. For these reasons, I reviewed both the current and forecasted levels of inflation and interest rates.

Q. WHAT ABOUT THE CURRENT ECONOMIC ENVIRONMENT DID YOU FIND IMPORTANT FOR YOUR ANALYSIS OF THE COST OF CAPITAL IN THIS PROCEEDING?

A. Entering the third quarter of 2006, economic activity is continuing to expand, although at a decelerating rate. As shown on Schedule DAM-1, the consensus forecast, as provided by *Blue Chip Financial Forecasts ("Blue Chip"),* predicts real GDP growth of 2.6 percent in the third and fourth quarter of 2006 and 2.7 percent for the first half of 2007.

The economy is also showing signs of increasing inflation after several years of stable prices. The consensus forecast for December-over-December core Consumers' Price Index ("CPI") growth (which excludes food and energy costs) is 2.6 percent for 2006. The Federal Open Market Committee ("FOMC"), in the minutes from its August 8, 2006 Committee Meeting, stated:

> Headline inflation continued to move up, on balance, in recent months, and consumer prices increased at a faster pace in the second quarter than over the previous twelve months. Consumer energy prices, while declining slightly in June, surged during the second quarter, on net. Core consumer prices also continued to rise, boosted by an acceleration in shelter costs, particularly those for owner-occupied residences, and some pass-through of energy cost increases. Higher oil prices showed through in producer prices for a variety of energy-intensive intermediate goods. Rising import prices, higher domestic rates of capacity utilization, and strong global demand for materials were factors underlying an acceleration in core prices for intermediate materials.

Q. YOU MENTIONED INFLATION LEVELS. CAN YOU ELABORATE UPON RECENT AND FORECASTED INFLATION RATES, AND WHY THEY WERE IMPORTANT TO YOUR ANALYSIS?

A. The Consumer Price Index increased 0.2 percent in August 2006 following a 0.4 percent increase in July. Core CPI increased 0.2 percent in August for the second consecutive month. The expected 2.8 percent rate of core inflation for 2006 is almost double that of the 1.5% rate of three years ago. This large increase reveals a broadening of inflationary pressures in the economy. As shown in Schedule DAM-1, *Blue Chip* is forecasting the CPI to increase in a range between 2.6 percent and 3.4 percent for the remainder of 2006. Increasing inflationary pressures are troubling to the financial markets and have the full attention of Federal policymakers. On August 22nd, Chicago Federal Reserve President Michael Moskow cautioned, "More rate hikes may still be necessary to cut inflation."

And as cited by *Blue Chip*[1], he also indicated that the risks is more toward inflation being too high than growth being too low.

Manufacturing activity is continuing to increase nationwide, putting pressure on the labor markets while health care and post-retirement costs continue to be a concern. Consumer spending, which accounts for two thirds of economic activity, has been increasing, albeit slowly, weighted down by sluggish sales of autos and housing related goods. Housing markets and construction activity are softening throughout the country, at least in part because of rising interest rates. Schedule DAM-2 illustrates the historical trends of GDP growth, unemployment and inflation statistics, and these statistics, which reveal the inflationary pressures, are examples of what the Federal Reserve evaluates when considering monetary policy.

Q. HOW HAS THIS ECONOMIC ACTIVITY AFFECTED INTEREST RATES?

A. The state of the economy and economic expectations are important background for my cost of capital analysis because increasing inflationary pressures almost certainly lead to actions by the Federal Reserve to increase interest rates. For example, the Federal Open Market Committee has raised interest rates 17 times since June 2004. Although the FOMC recently has forgone raising short-term rates, it has indicated it will remain vigilant regarding inflation concerns. In its August 8, 2006 press release[2], the FOMC stated:

> …the Committee judges that some inflation risks remain. The extent and timing of any additional firming that may be needed to address these risks will depend on the evolution of the outlook for both inflation and economic growth, as implied by incoming information.

[1] *Blue Chip Financial Forecasts*, September 1, 2006.
[2] Federal Reserve Release, August 8, 2006.

Q. CAN YOU SUMMARIZE WHAT YOU FOUND TO BE THE SIGNIFICANT INTEREST RATE DEVELOPMENTS?

A. As the economy expands, the Federal Reserve has signaled it will raise interest rates as necessary to keep inflation at bay. Regarding the outlook for inflation and Federal Reserve action, the Richmond Federal Reserve Bank President, Andrew Lacker, recently described the inflation outlook as, "…borderline acceptable and perhaps even beyond." Fed Chairman Ben Benanke also has stated, "there are some upside inflation risks in the economy" and "…some additional firming of policy might yet be needed."

Q. DID YOU STUDY THE RECENT AND FORECASTED BOND RATES?

A. Yes. Bond prices have decreased substantially in 2006, thereby raising yields on bonds to their highest level since 2002. As shown on Schedule DAM-3, the 10-year Treasury Bond and the Aaa-corporate rate are currently about 5.0 percent and 5.8 percent, respectively. Most significantly, as shown in Schedule DAM-4, analysts expect long-term bond rates to continue rising. The *Value Line* forecasts for the Baa-corporate rate and the 10-year Treasury rate are for continuing increases to 6.7 percent and 5.5 percent respectively through 2009.

Q. WHY ARE THESE ECONOMIC CONDITIONS IMPORTANT TO THIS PROCEEDING?

A. The rates set in this proceeding will be in effect during a period of rising inflation and interest rates. Because of its restructuring and capital requirements, Aquila, Inc. will be in the market to acquire permanent capital to support continued and expanded utility service during this period. Also, rising inflation and interest rates adversely affect the cost of a gas utility's debt, and the combination of the high cost short-term debt--which funds natural gas purchases--and high natural gas prices significantly increases business risk to investors. This increases the risk to common stockholders that they will achieve their anticipated returns on investment.

SELECTION OF COMPARABLE COMPANIES

Q. WHAT CRITERIA DID YOU USE TO SELECT THE UTILITIES THAT YOU IDENTIFIED AS COMPARABLE TO AQUILA NETWORKS - NEBRASKA FOR YOUR ANALYSIS?

A. I selected a group of local gas distribution utilities for comparative analysis that have typical risks that healthy LDCs face. I first selected the comparable companies from a group of gas distribution companies reported by *Value Line.* Second, because of the importance of size in determining the cost of capital of a utility, I limited the group of distribution companies to firms with a market capitalization of less than $2 billion. Third, I excluded companies that do not pay a dividend. Fourth, I eliminated those companies that are not primarily gas distributors, and finally, I dropped LDCs that are actively involved in a merger.

Q. WOULD YOU EXPLAIN WHY YOU DID NOT USE AQUILA, INC.'S FINANCIAL CRITERIA TO SELECT A GROUP OF COMPARABLE COMPANIES FOR YOUR ANALYSIS?

A. Aquila, Inc. is still in the process of restructuring itself to a utility-only business. Selecting companies with similar financial characteristics to a financially viable utility provides a benchmark for comparison and aids in the interpretation of the statistics of Aquila Networks - Nebraska. Methodologically, I used this set of comparable companies as a representative "sample" of the gas distribution sector and, by inference, representative of the cost of capital of a utility with these financial characteristics. For this reason, it is important to determine the risks and the associated costs of common stock equity of gas distribution utilities that are similar to Aquila Networks – Nebraska. I selected this group of companies by holding some key characteristics constant when I selected the companies for comparison. Using a group of comparable companies analytically is also consistent with the regulatory objective of determining the cost of investing in securities of equivalent risks.

Q. WHAT COMPANIES DID YOU SELECT AS COMPARABLE TO AQUILA NETWORKS - NEBRASKA AND THEREFORE SUITABLE FOR YOUR ANALYSIS?

A. Using the set of criteria mentioned above, I determined that eight primarily natural gas companies were similar in key respects to Aquila Networks - Nebraska. This group includes: Laclede Group, New Jersey Resources, NICOR, Inc., Northwest Natural Gas, Piedmont Natural Gas, South Jersey Industries, Southwest Gas and WGL Holdings, Inc.

CAPITAL STRUCTURE

Q. WHAT IS THE APPROPRIATE CAPITAL STRUCTURE FOR AQUILA NETWORKS - NEBRASKA IN THIS PROCEEDING?

A. As I have illustrated in Schedule DAM-5, the Company has a total capitalization of $273,050,946 at June 30, 2006. The Long-Term Debt is $134,540,892, or 49.27 percent of total capital, and the Common Equity is $138,510,054 or 50.73 percent of total capital.

Q. YOU DID NOT INCLUDE ANY SHORT-TERM DEBT IN THIS CAPITAL STRUCTURE THAT YOU ARE RECOMMENDING FOR AQUILA NETWORKS

- NEBRASKA. WHY DID YOU EXCLUDE SHORT-TERM DEBT IN YOUR RECOMMENDED CAPITAL STRUCTURE?

A. I only included components of capital in the capital structure that are part of the permanent capital that supports physical utility assets providing utility services currently and during the period that the rates set in this proceeding will be in effect.

Q. IS THIS CAPITAL STRUCTURE THAT YOU ARE RECOMMENDING IN THIS PROCEEDING, THE CURRENT CAPITAL STRUCTURE OF AQUILA, INC.?

A. No. The restructuring of Aquila, Inc., which includes the sale of non-domestic investments and most non-regulated businesses, has affected significantly its current capital structure. Because this restructuring has been on-going, the current capital structure is a carry-over from a prior more diverse company. This is less representative of a LDC capital structure than the divisional capital structure of Aquila Networks - Nebraska. For example, Aquila, Inc. is still in the process of moving proceeds from the sales of various businesses to pay down outstanding debt, and the capital structure is not representative of the permanent capital that supports the utility service in Nebraska.

Q. HOW DOES THE CURRENT CAPITAL STRUCTURE OF AQUILA, INC. COMPARE TO THE CAPITAL STRUCTURE OF A TYPICAL LDC?

A. As I illustrate in Schedule DAM-6, according to *Value Line,* Aquila, Inc.'s current common equity ratio is only 43 percent. This is a lower common equity ratio than all of the comparable LDCs except Southwest Gas. Aquila, Inc.'s common equity ratio is also much lower that the average common stock equity ratio for the group of comparable LDCs, which is 54.7 percent. Notably, *Value Line* is also predicting, that following the present restructuring, that Aquila, Inc.'s common equity ratio will be 53.5 percent in the

2009-11 time period. This is closer to the common equity ratio of a regulated LDC in current markets, and it provides further evidence that the current, low common equity during this period of restructuring is not appropriate for setting rates of Aquila Networks - Nebraska. Of course, it is also important that the rates set in this proceeding are likely to run, at least, into the forecast period.

Q. DID YOU STUDY THE CHANGES IN AQUILA, INC.'S COMMON EQUITY RATIO IN RECENT YEARS?

A. Yes. As Schedule DAM-7 shows, I compared Aquila, Inc.'s growth in common stock outstanding, as reported by *Value Line*, to the growth of common stock outstanding of the comparable LDCs. Obviously, Aquila, Inc.'s growth in common stock outstanding has been much higher than any of the comparable distribution utilities during this period. This is not surprising, however, because Aquila, Inc.'s restructuring has required a de-leveraging of its balance sheet. This makes the issuance of common stock a more attractive vehicle to acquire the capital needed for plant expansion and to reduce debt.

Q. FROM YOUR ANALYSIS OF THE COMPANY, DO YOU BELIEVE THAT THE COMMON EQUITY RATIO OF AQUILA, INC. WILL APPROACH THE LEVEL PREDICTED BY *VALUE LINE?*

A. Yes. As Aquila, Inc.'s restructuring leads to primarily utility operations, it is only logical that analysts would expect the company to acquire a capital structure that is characteristic of that industry sector.

<u>COST OF LONG-TERM DEBT</u>

Q. FROM YOUR ANALYSIS, WHAT IS THE APPROPRIATE COST OF LONG-TERM DEBT FOR AQUILA IN THIS PROCEEDING?

A. As shown in Schedule DAM-8, the weighted average cost of long-term debt that is appropriate for Aquila in this proceeding is 7.13 percent. This is the cost of long-term debt that Aquila, Inc. used to acquire the long-term assets that provide utility service to Nebraska customers. This, however, is a conservative cost of long-term debt because of Aquila, Inc.'s policy of assigning investment grade costs to debt issues in order to protect ratepayers from the capital costs of the non-regulated businesses.

FINANCIAL RISK

Q. YOU STATED PREVIOUSLY THAT YOU INVESTIGATED THE "FINANCIAL RISK" OF AQUILA. WHAT DO YOU MEAN BY THE TERM FINANCIAL RISK?

A. Financial risk to the common stock holders of a company is the risk that they incur because the claims of the debt instruments must be paid prior to any returns accruing to common stock. In general, the lower the common stock equity ratio, the greater is the relative, prior obligation owed to debt holders. Consequently, all things equal, the risk faced by holders of a company's common stock is greater if the common equity ratio is smaller.

Q. IS FINANCIAL RISK AN IMPORTANT CONSIDERATION IN THIS PROCEEDING?

A. Yes. Financial risk is an important determinant of the required return. It is especially important in this proceeding because of the differential between the common equity ratios of the parent Aquila, Inc. and the operating division, Aquila Networks - Nebraska. Notably, the average common equity ratio of the comparable companies of 54.7 percent is higher than the common equity component of the Aquila Networks - Nebraska.

Q. DID YOU COMPARE THE FINANCIAL RISK OF AQUILA, INC. TO THAT OF A TYPICAL LDC?

A. Yes. I think that one can reveal the relative financial risk of Aquila, Inc. by comparing some of its credit measures to similar measures for the comparable LDCs. I have illustrated this comparison in Schedule DAM-9 using *Value Line's* measure of "Financial Strength" And Standard & Poor's "Credit Rating." *Value Line* ranks Aquila, Inc. a "C", placing it in the group second from the bottom of all companies that *Value Line* ranks. None of the comparable LDCs have a financial strength rating that low, and only Southwest has a rating as low as a "B" which is average for all companies that *Value Line* follows. *Value Line* rates four of the gas distribution companies as "A". Also, as that schedule shows, Standard & Poor's rates Aquila, Inc.'s credit a B, which is four levels below investment grade. All of the other gas utilities have investment grade credit ratings of "BBB" or above and six of the eight are "A" rated or above. As noted previously, greater financial risk means that in order to invest, investors will look for higher compensating common stock returns. Consequently, by using the capital structure of the operating division in Nebraska in this proceeding to determine the allowed returns, I can use the estimated cost of the comparable LDCs as a guide for determining a recommended allowed return because the capital structure of the operating division in Nebraska is closer to the industry norm.

<u>BUSINESS RISK</u>

Q. YOU ALSO STATED THAT YOU INVESTIGATED THE "BUSINESS RISK" OF AQUILA. HOW DID YOU DEFINE BUSINESS RISK?

A. Business risk is the exposure of the returns to common stockholders resulting from the vagaries of business operations. In many respects, the most important business risks for LDCs are: competition from other fuels, local economic conditions, rising gas costs that reduce sales, the impact of rising inflation and interest rates, and any uncertainty with the recovery of the costs of purchased gas. High gas costs, for example, lead to increased working capital and short-term debt requirements needed to pay suppliers until the LDC recovers gas costs through rates. The rising short-term interest rates further exacerbate the situation. Furthermore, LDCs face rising, unanticipated bad debt expenses and accounts receivable in these markets. In my analysis, I considered these and other general business risks.

Q. DO YOU BELIEVE THAT BUSINESS RISK IS AN IMPORTANT CONSIDERATION IN THIS PROCEEDING?

A. Yes. Business risk is also a prime determinant of the required rate of return. The business risks that I have described above are risk factors that are common to the natural gas industry, and Aquila Networks - Nebraska undoubtedly faces similar business risks.

Q. DID YOU DETERMINE ANY MEASURES OF BUSINESS RISK THAT PERTAIN SPECIFICALLY TO THE OPERATIONS OF AQUILA, INC.?

A. Yes. I reviewed several indices of business risk of Aquila, Inc. as reported by financial analysts, which I reported in Schedule DAM-10. Although these measures in some respects combine financial and business risks together as a common measure, they are likely to be closer to business risk than the credit measures mentioned previously. I compared the measures for Aquila, Inc. with those for the group of comparable companies.

Q. ARE YOU AWARE IF AQUILA NETWORKS – NEBRASKA HAS SOME OF THE RISKS THAT AFFECT THE LDC SECTOR?

A. Yes. This is clearly the case. It appears that declining use per customer, in many instances is similar in Nebraska to other parts of the country; customers' switching to heat pumps is one cause. Also, declining population in some areas of the system also is an added risk.

A more important, and somewhat unusual, factor is the competition in the area in and around Omaha. As I understand the competitive situation for Aquila Networks – Nebraska, it does not have a certificated service territory in this area. This is, of course contrary to the economic rationale for regulation that I discussed previously. That is, traditionally a certificated service territory is the conceptual justification for regulation and lower capital costs for an LDC because it precludes direct competition and this lowers risks to investors. Consequently, this is evidence that Aquila Networks - Nebraska has more business risk exposure than the typical LDC.

Q. YOU IDENTIFIED ADDITIONAL RISK MEASURES OF AQUILA, INC. WHAT DID THESE ADDITIONAL MEASURES OF RISK SHOW?

A. These measures also show very clearly the sharp risk distinction between Aquila, Inc. and the comparable LDCs. I have illustrated several key statistics from *Value Line* and Standard & Poor's in Schedule DAM-10. As this schedule shows very clearly, analysts view Aquila, Inc. quite differently from the selected LDCs in the current markets. Using *Value Line* measures of "Safety", "Price Stability", "Price Growth" and "Earnings Predictability," analysts will perceive Aquila, Inc.'s common stock to be a much more risky investment than the common stock of the other, comparable LDCs. For example, the "Safety" rank is "a measurement of potential risk associated with individual common stocks. The value shows where an individual stock is in relation to the entire universe of Value Line's stocks.[3]" Stocks ranked 1 (Highest) and 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) and 5 (Lowest) are likely to underperform most stocks over the next 12 months. Aquila, Inc. is rated a "5". The lowest ranking of the comparable LDCs is a "3". Also, in its "Business Profile", Standard & Poor's ranks Aquila, Inc. an "8" which is distinctively much more risky than any of the comparable LDCs, which average only a "2.4".

Q. ARE YOU AWARE OF ANY OTHER SPECIFIC BUSINESS RISKS THAT MAY BE UNIQUE TO AQUILA NETWORKS - NEBRASKA?

A. One business risk factor that could be important for ratemaking going forward is the effect of Aquila, Inc.'s recent restructuring. Of course, economies of scale are one of the benefits of company size, and this has been a driving factor in the mergers and acquisitions in the natural gas distribution sector in recent years. As Aquila, Inc. has disposed of several operating companies in recent years, the reallocation of centralized costs over a smaller customer and utility plant base could be a risk to common stock holders. That is, if the allocation of these costs reduces the likelihood of their recovery, this is a risk to common equity of Aquila Networks - Nebraska.

Q. IN YOUR OPINION, HAS THIS RESTRUCTURING INCREASED THE RISK TO THE COMMON EQUITY OF AQUILA NETWORKS - NEBRASKA?

A. No, I believe that the restructuring has not increased the cost of common equity of Aquila Networks - Nebraska. In fact, as Schedule DAM-11 shows, the Operations & Maintenance Expenses per Customer and the Net Plant per Customer for Aquila

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[3] "How to Invest in Common Stocks: The Complete Guide to Using the Value Line Investment Survey," (2003: Value Line Publishing, Inc., New York), p. 41.

Networks – Nebraska are within the range of my comparable companies. Of course, these metrics may require further interpretation; utilities with a more concentrated service territory may have lower costs per customer than more rural systems. Consequently, I also compared Aquila Networks – Nebraska to Kinder Morgan - Nebraska. This comparison also demonstrates that the restructuring of Aquila, Inc. has not adversely affected the cost per customer of Aquila Networks – Nebraska and increased the risks to common equity.

Q. FROM A RATEMAKING STANDPOINT, SHOULD THE HIGHER RISK OF AQUILA, INC. INFLUENCE THE COST OF CAPITAL OF THE UTILITY OPERATING DIVISIONS?

A. Aquila, Inc. has tried to isolate the impact of the credit and risk problems of the parent from the regulated utility, and this is a sound policy in my opinion. Nonetheless, I think recognizing this risk differential is important as a background for this analysis of Aquila's cost of capital. For example, this sharp distinction in the risk of Aquila, Inc. and the comparable LDCs is further confirmation that Aquila, Inc.'s high risk capital structure is inappropriate for ratemaking for Aquila Networks – Nebraska in this proceeding.

Q. IN YOUR OPINION, SHOULD THIS RISK DIFFERENTIAL BETWEEN AQUILA, INC. AND THE TYPICAL LDCS CHANGE IN THE FUTURE?

A. In the future, as Aquila, Inc. evolves as a parent company of a group of regulated utilities, this risk differential noted by analysts should diminish. In fact, Aquila should experience the potential economies of scale that afford cost savings to an utility operating division of a larger company. Typically, a utility operating division flows those lower costs through to rates, and that is the potential inherent benefit in this structure. The mergers and combinations of utilities in recent years is evidence that it is an industry trend to seek these economies.

Q. WHEN YOU REVIEWED THE COMMON STOCK EARNINGS OF THE COMPANIES THAT YOU STUDIED, WHAT DID THIS SHOW?

A. The recent common stock losses of Aquila, Inc., which fortunately are improving, set it apart from the positive earnings and earnings growth of the group of comparable gas distribution utilities. I have shown this comparison in Schedule DAM-12. Similarly, comparing the percentage returns on common equity of Aquila, Inc. to the comparable utilities confirms this risk differential. For example, *Value Line* estimates the average return on common stock equity for this group of companies in 2006 at 11.8 percent, with a high for New Jersey Resources of 16.0 percent. With its financial difficulties, Southwest Gas, at a return to common equity of 9.5 percent, is the only one of these LDCs that has returns in the single digits. I have demonstrated this comparison in Schedule DAM-13.

Q. WERE AQUILA, INC.'S LOSSES AND LOW FORECASTED COMMON STOCK EARNINGS IMPORTANT TO YOUR ANALYSIS IN ANY OTHER WAYS?

A. Because analysts and investors are not anticipating a positive return from an investment in Aquila, Inc., this renders a meaningful DCF analysis of Aquila, Inc. using earnings growth rates impossible.

Q. WHEN YOU REVIEWED THE COMMON STOCK DIVIDENDS, WHAT DID YOU DETERMINE?

A. This comparison provided more evidence confirming the financial distinction between the comparable gas distribution utilities and Aquila, Inc. at this point in time. As I have illustrated in Schedule DAM-14, each of the comparable gas distribution utilities has paid a dividend in each of the last five years. This is in contrast to Aquila, Inc. which has not paid a dividend since 2002. Moreover, *Value Line* predicts that it will pay no dividends through the period 2009-11.

Q. IS IT IMPORTANT TO YOUR ANALYSIS THAT AQUILA, INC. HAS NOT PAID A DIVIDEND IN RECENT YEARS AND THAT *VALUE LINE* FORECASTS THAT IT WILL NOT PAY A DIVIDEND IN THE 2009-11 PERIOD?

A. Yes. Because analysts and investors are not anticipating a dividend from Aquila, Inc., analytical methods based on the near-term return on investment through dividends, such as the DCF, will not produce meaningful results.

<u>COST OF COMMON STOCK</u>

Q. YOU ALSO STATED PREVIOUSLY THAT YOU CALCULATED THE COST OF COMMON STOCK EQUITY FOR A COMPARABLE GROUP OF GAS DISTRIBUTION COMPANIES. WHAT METHODS DID YOU USE?

A. I used the two most common methods for estimating the cost of common stock in regulatory proceedings, the Discounted Cash Flow and the Capital Asset Pricing Model. The DCF analysis, which is probably the most commonly referenced method in regulatory proceedings, and the CAPM, which provides a longer-term perspective to the analysis compliment on another.

For comparative purposes, I set out to apply each of these methods to estimate the cost of common stock of Aquila, Inc. and each of the comparable companies. As a result of the sharp risk differentials observed previously, this comparison is important analytically. However, because of the difficulty in assessing the growth statistics of Aquila, Inc., the DCF of Aquila, Inc. estimates are not reliable. The CAPM for Aquila, Inc. incorporates the greater risk differential. Consequently, these results require interpretation in this context.

Of course, just mechanically applying either of these methods is a sterile analysis, so I investigated the assumptions underlying the methods in order to interpret the results if these assumptions remained satisfied in this case. I also reviewed academic literature related to the use of these two techniques. In this way, I interpreted the results in the context of their strengths and weaknesses of these methods, and, to put them into perspective, I evaluated these calculations in the context of current market conditions.

DISCOUNTED CASH FLOW METHOD

Q. YOU MENTIONED THAT YOU USED THE DCF METHOD FOR DETERMINING COST OF COMMON STOCK. CAN YOU DEFINE THE DCF METHODOLOGY FOR MEASURING COST OF COMMON EQUITY?

A. Yes. The DCF calculation of the investor's required rate of return can be expressed by the following formula:

$$K = D/P + g$$

Where:
- K = cost of common equity
- D = dividend per share
- P = price per share and
- g = rate of growth of dividends, or alternatively, common stock earnings.

In this expression K is the capitalization rate required to convert the stream of future returns into a current value.

Q. YOU MENTIONED THE UNDERLYING ASSUMPTIONS OF THE COST OF CAPITAL MODELS. WHAT ASSUMPTIONS UNDERLYING THE DCF METHOD ARE IMPORTANT WHEN ESTIMATING THE COST OF COMMON STOCK EQUITY IN PRACTICE?

A. As an example of underlying assumptions of the DCF, David Parcell stated in *The Cost of Capital—A Practitioner's Guide,*[4] that the general DCF model has the following four key assumptions:

> 1. Investors evaluate common stocks in the classical economic framework.
> 2. Investors discount the expected cash flows at the same rate (K) in every future period.
> 3. K corresponds only to the specific steam[sic] of future cash flows.
> 4. Dividends, rather than earnings, constitute the source of value.

These key assumptions are important; when not realized in practice, they can lead to incorrect measures of the cost of common equity. In turn, this may lead to misinterpretation of the results using the DCF method.

Q. WHAT DO YOU SEE AS STRENGTHS OF THE DCF METHOD?

A. I believe that its principal strength is its theoretically soundness. Recognizing that an investor expects a return on investment in the form of dividends and capital gains, the DCF implies that the investor is willing to pay a market price that is equal to the present value of that stream of earnings to acquire the common stock. Using these market relationships, an analyst can estimate the opportunity cost of an investor's funds, which is consistent with the regulatory objective of setting an allowed return equal to the returns to investments of equivalent risk. As a market-based measure recognizing investors' expectations, the DCF relates the market price information and the company's dividend

[4] Parcell, David, *The Cost of Capital—A Practitioner's Guide,* Society of Utility and Regulatory Analysts, 1997, pp. 8-5, 8-6.

and earnings performance to determine the value that investors place on anticipated returns.

Another common advantage in regulation is that the DCF is the most common method analysts use to measure the cost of common equity in regulatory proceedings. Consequently, persons involved in regulatory proceedings are familiar with it.

WEAKNESSES OF THE DCF

Q. WHEN USED IN A UTILITY RATE PROCEEDING, WHAT DO YOU SEE AS IMPORTANT WEAKNESSES OF THE DCF METHOD?

A. The DCF has both conceptual and data issues that may lead to misinterpretation of the calculated results. Either or both can create problems in a ratemaking proceeding.

Q. YOU STATED THAT CONCEPTUAL PROBLEMS OF THE DCF MAY LEAD TO MISINTERPRETATION OF THE CALCULATED RESULTS. WHAT CONCEPTUAL PROBLEMS OF THE DCF MAY BE IMPORTANT WHEN AN ANALYST USES IT TO ESTIMATE THE COST OF CAPITAL IN A RATE PROCEEDING?

A. A significant problem of the DCF method which can lead to a misinterpretation in a rate proceeding is the very nature of the DCF method. The DCF estimates the marginal cost of common stock equity of a company, and often analysts applying the data do not recognize the theoretical significance of this. That is, the DCF provides an estimate of the minimal return necessary to attract marginal, or incremental, investment in the common stock equity. However, the method does not account for any other factors that may affect the ability of the company to earn that return.

Q. IN REGULATORY PRACTICE, WHY IS THE MARGINAL COST NATURE OF THE DCF SIGNIFICANT?

A. Analysts interpreting the results of the DCF calculations may not recognize their context or what they truly represent. Consequently, the DCF-based calculations may be misleading. For example, the DCF calculated cost of common equity result does not provide any cushion in the estimation of the cost of capital. When using these results as a basis for a recommended allowed return in a regulatory proceeding, the bare-bones calculations may not provide a regulated company a reasonable likelihood to earn its allowed return. In fact, this misunderstanding of the DCF results can virtually assure that a regulated company will not have the opportunity to earn its allowed return.

Q. IN YOUR EXPERIENCE IS IT COMMON FOR REGULATORS AND ANALYSTS TO RECOGNIZE THIS CHARACTERISTIC OF THE DCF METHOD?

A. Yes, it is. Regulators and analysts often apply adjustments to compensate for the marginal cost nature of the DCF adjustment. For example, some analysts specifically apply a flotation adjustment. The flotation adjustment specifically recognizes that the measurement of the market-based DCF estimate of the cost of capital does not always incorporate the costs of issuing common stock, i.e., legal fees, investment banker fees and publication costs of a prospectus. Some analysts also apply an adjustment for “market pressure” associated with the sale of securities. This also is a direct recognition that an analyst should recognize the effects of market activities not encompassed in the current DCF estimate when setting rates for a future time period.

Q. RECOGNIZING THE MARGINAL COST NATURE OF THE DCF AND THE NEED OF A REGULATED UTILITY TO BE ACTIVE IN THE FINANCIAL MARKETS, DO YOU RECOMMEND CALCULATING A FLOTATION ADJUSTMENT?

A. No, I believe that focusing on the high end of the DCF results is adequate compensation for the regulated utility, and I believe that these are results that fall within the distribution of estimated cost of common equity. This also provides market measured estimates of the cost of such factors as flotation costs and other market effects. This, in my opinion, directly recognizes the marginal cost nature of the DCF method.

Q. TO YOUR KNOWLEDGE, HAVE REGULATORY COMMISSIONS RECOGNIZED THESE LIMITATIONS OF THE DCF WHEN USED IN RATE PROCEEDINGS TO DETERMINE THE COST OF COMMON EQUITY?

A. Yes, commissions have recognized some of these difficulties. In one example addressing these factors directly, the Indiana commission in a 1990 decision recognized that the assumptions underlying the DCF model rarely, if ever, hold true.[5] This commission stated that an "…unadjusted DCF result is almost always well below what any informed financial analyst would regard as defensible and therefore requires an upward adjustment based largely on the expert witness' judgment."[6]

Q. HAVE ANALYSTS PERFORMED STUDIES REGARDING WHICH DATA USED IN A DCF ANALYSIS ARE MOST LIKELY TO CAPTURE INVESTORS' EXPECTATIONS ABOUT THE FUTURE RETURNS?

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[5] Phillips, Charles F., Jr. and Robert G. Brown, *Chapter 9: The Rate of Return,* The Regulation of Public Utilities: Theory and Practice, (1993: Public Utility Reports, Arlington, VA) p. 423.
[6] Ibid, *In re Indiana Michigan Power Company,* 116 PUR4th 1, 17 (Ind. 1990).

A. Yes. As early as 1982, published academic studies showed that analysts' forecasts were superior to historical trended growth rates as predictors of growth rates for DCF analyses.

Q. CAN YOU CITE SOME OF THE STUDIES THAT DEMONSTRATED THAT INVESTORS LOOK TO ANALYSTS' FORECASTS WHEN MAKING INVESTMENT DECISIONS?

A. Yes. A number of authors have addressed the merits of analysts' forecasts in a DCF analysis of the cost of capital. For example, a well-known financial textbook by Brigham and Gapenski states that analysts' growth rate forecasts are the best source for growth measures in a DCF analysis:

> Analysts' growth rate forecasts are usually for five years into the future, and the rates provided represent the average growth rate over the five-year horizon. Studies have shown that analysts' forecasts represent the best source for growth for DCF cost of capital estimates.[7]

Research reported in the academic literature supports this position also. For example, Vander Weide and Carleton found:

> …overwhelming evidence that the consensus analysts' forecast of future growth is superior to historically oriented growth measures in predicting the firm's stock price….Our results are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy-and-sell decisions.[8]

As to the use of the DCF in utility regulatory proceedings, Timme and Eisemann examined the effectiveness of using analysts' forecasts rather than historical growth rates. They concluded:

> The results show that all financial analysts' forecasts contain a significant amount of information used by investors in the determination of share prices not found in

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[7] Brigham, Eugene F., Louis C. Gapenski, and Michael C. Ehrhardt, "Chapter 10: The Cost of Capital," <u>Financial Management Theory and Practice, Ninth Edition</u> (1999: Harcourt Asia, Singapore), p. 381.

[8] Vander Weide, James H. and Willard T. Carleton, "Investor Growth Expectations: Analysts vs. History," *The Journal of Portfolio Management*, Spring 1988, pp. 78-82.

> the historical growth rate….The results provide additional evidence that the historical growth rates are poor proxies for investor expectations; hence they should not be used to estimate utilities' cost of capital.[9]

Q. ARE YOU AWARE OF ANY OTHER EMPIRICAL INFORMATION THAT FOCUSES ON THE IMPORTANCE OF COMMON STOCK EARNINGS?

A. Yes. In an "event analysis", a colleague and I compared the market reactions of announced dividends and common stock earnings that were likely to be a surprise to the market. That is, for a group of electric utilities we compared the market reactions to dividend announcements and common stock earnings announcements. Specifically, we looked at the price impact of both earnings announcements and dividend announcements that exceeded *Value Line's* projected levels. Among these companies there were 8 dividend announcements and 19 common stock announcements that exceeded analyst's expectations during the period from September 2001 to December 2003. By developing ratios of a utility's common stock price to the Dow Jones Utility Index, we statistically isolated the impact of these announcements, and linked them to contemporaneous price changes. As Schedule DAM-15 shows, the impact on market prices of the unexpected earnings per share announcement in these cases is dramatic and obvious, and the impact of unexpected dividend announcements is seemingly less so.

Q. WHEN DEVELOPING YOUR DCF ANALYSIS, WHAT DID YOU LEARN ABOUT THE RECENT COMMON STOCK EARNINGS AND DIVIDEND PAYMENTS OF THE COMPANIES THAT YOU STUDIED?

A. I reviewed the dividend and earnings history of the companies studied. As I have illustrated in Schedule DAM-16, the dividends have grown at a lower rate than earnings

[9] Timme, Stephen G. and Peter C. Eisemann, "On the Use of Consensus Forecasts of Growth in the Constant Growth Model: The Case of Electric Utilities," *Financial Management*, Winter 1989, pp. 23-35.

per share in recent years, but this is not surprising in light of the increased competition in the gas distribution industry. Under these increasingly competitive circumstances, prudent boards of directors are likely to conserve cash and refrain from increasing dividends even as earnings grow. Although this relationship may change eventually following the tax reduction on dividends in 2003, the data that I reviewed concerning the comparable LDCs does not yet show this impact.

Q. HOW DID YOU DETERMINE COMMON STOCK PRICES FOR YOUR DCF ANALYSIS?

A. Of course, I was interested in current market valuations; however, recognizing that rates from this proceeding will be in effect for a number of years, I also examined prices over a longer time period. I obtained common stock prices for the past year reported by the *Wall Street Journal.* I also selected current prices from a recent two-week period as reported by *YAHOO! Finance.*

Q. PLEASE EXPLAIN THE FINDINGS FROM YOUR DCF ANALYSIS.

A. Because of the unavailability of DCF estimates for Aquila, Inc., in this analysis I concentrated on the results of the comparable LDCs as cost of common equity benchmarks. In this analysis, for a dividend growth rate I combined historical and forecasted dividend growth rates and used the common stock prices for the past year. This produced low estimates for the comparable companies. I show the results of this DCF calculation in Schedule DAM-17. These results are on the average for the group between 6.23 percent and 7.04 percent. , However, these results are so close to the current level of short-term debt rates and the coupon bond rate of even investment grade utilities that they are not credible measures for the cost of common equity of Aquila in this proceeding. I also used a current common stock share price in a DCF calculation, and it also produced non-credible results for ratemaking. As Schedule DAM-18 shows, these results are 6.40 percent to 6.45 percent on the average which are lower than the current yield on Moody's Baa corporate bonds of 6.59 percent. Schedules DAM-19 and DAM-20 combine the historical and forecasted earnings per share growth rates showing that this DCF produced an extremely high range of estimates. It ranges from a low of 3.64 percent for NICOR to a high of 11.85 percent for the South Jersey Industries when I used the 52-week share prices. After removing NICOR because of its negative growth rate, the model produces an average for the group of 9.75 percent to 10.57 percent. The high-end of the projected earnings per share growth rate DCFs for the comparable LDCs of 10.00 percent and 9.42 percent are probably the most relevant for Aquila Networks - Nebraska in this proceeding. Using the 52-week prices, Southwest Gas is the highest DCF result at 12.26 percent and using recent prices it is 11.49 percent. I have illustrated these results in Schedules DAM-21 and DAM-22.

<u>CAPITAL ASSET PRICING MODEL</u>

Q. YOU STATED THAT YOU USED THE CAPITAL ASSET PRICING MODEL IN YOUR ANALYSIS. WHAT IS THE CAPITAL ASSET PRICING MODEL?

A. The Capital Asset Pricing Model is a risk premium method that measures the cost of capital based on an investor's ability to diversify by combining securities of various risks into an investment portfolio. It measures the risk differential, or premium, between a given portfolio and the market as a whole. The diversification of investments reduces the investor's total risk. However, some risk is non-diversifiable, e.g., market risk, and investors remain exposed to that risk. The theoretical expression of the CAPM model is:

$$K = R_F + ß\,(R_M - R_F)$$

Where:

K = the required return.
R_F = the risk-free rate.
R_M = the required overall market return; and
ß = beta, a measure of a given security's risk relative to that of the overall market.

In this expression, the value of market risk is the differential between the market rate and the "risk-free" rate. Beta is the measure of the volatility, as a measure of risk, of a given security relative to the risk of the market as a whole. By estimating the risk differential between an individual security and the market as a whole, an analyst can measure the relative cost of that security compared to the market as a whole.

Q. IN YOUR OPINION, WHAT ARE THE ADVANTAGES WHEN USING THE CAPM IN A RATEMAKING PROCEEDING?

A. The CAPM, as a risk premium method, provides a longer-term, more stable perspective of the cost of capital when applied in ratemaking than that of the more volatile DCF analysis. The CAPM takes current debt costs as a basis, or benchmark, for measuring the cost of common stock, which provides this analytical stability. In this way, the CAPM links the incremental cost of capital of an individual company with the risk differential between that company and the market as a whole. Although this is a rather imprecise method, it is a good tool for assessing the general level of the cost of a security.

Q. HOW CAN YOU TELL THAT THE CAPM IS A MORE STABLE MEASURE OF THE COST OF CAPITAL?

A. The CAPM results are likely to be similar for companies in the same industry with similar financial characteristics. In addition, the results are not likely to vary a great deal over time.

Q. WHAT PROBLEMS DO YOU PERCEIVE TO BE IMPORTANT WHEN ONE USES THE CAPM IN A RATEMAKING PROCEEDING?

A. The cost of capital calculations for a company are sensitive to the beta used in the analysis. This beta is a single measure of risk, so, consequently, the CAPM will not incorporate any risks not included in the measures of market volatility. Also, a number of analysts have shown that the CAPM overestimates the cost of capital of companies with betas greater than one and underestimates the cost of capital of companies with betas less than one. In regulation this is important, because most utilities have beta estimates less than one. For example, all of the comparable LDCs except NICOR have *Value Line* betas between 0.70 and 0.85. NICOR has a *Value Line* beta of 1.20. Also, notably Aquila, Inc. has a beta of 1.50.

Q. PLEASE EXPLAIN THE CAPM METHODOLOGY THAT YOU USED IN YOUR ANALYSIS.

A. I applied two different, but complementary, approaches to estimate a CAPM cost of capital. One of these methods examines the historical risk premium of common stock over high grade corporate bonds. The other integrates the risk premium of common stocks to long-term government bonds in recent markets. This method requires an adjustment for the bias because of company size that I mentioned previously. The financial literature has recognized this bias as an empirical problem for a long time, but correcting for this bias is a recent analytical development.

Q. YOU STATED THAT THE FINANCIAL LITERATURE RECOGNIZES THAT THE CAPM METHOD MAY REQUIRE AN ADJUSTMENT FOR A COMPANY'S SIZE. WHAT IS THE NATURE OF THIS RECOGNIZED BIAS?

A. R. W. Banz[10] and M. R. Reinganum[11] in the 1980s, for example, is a good reference pointing out this size bias. Reinganum examined the relationship between the size of the firm and its price-earnings ratio, finding that small firms experienced average returns greater than those of large firms that had equivalent risk as measured by the beta. Of course, the beta is the distinguishing measure of risk in the CAPM. Banz confirmed that beta does not explain all of the returns associated with smaller companies; hence, the CAPM would understate their cost of common equity. In the same time frame, Fama and French confirmed that the Banz analysis consistently rejected the central CAPM hypothesis that beta sufficed to explain investors' expected returns.[12]

Q. WHAT DID YOU MEAN WHEN YOU SAID THAT THE CAPM METHOD REQUIRES AN ADJUSTMENT?

A. Although repeated studies showed that the CAPM method possesses a bias that understates the expected returns of small companies, this remained only an empirical observation without a clear remedy. However, now Ibbotson Associates, which is the common source of data for the risk premium used in CAPM analyses, has developed an adjustment for this bias. Ibbotson Associates discusses the problem as follows:

> One of the most remarkable discoveries of modern finance is that of the relationship between firm size and return. The relationship cuts across the entire size spectrum but is most evident among smaller companies, which have higher returns on average than larger ones. Many studies have looked at the effect of firm size on return. [13]

[10] Banz, R.W., "The Relationship Between Return and Market Value of Common Stock," *Journal of Financial Economics*, March 1981, pp. 3-18.

[11] Reinganum, M. R., "Misspecification of Capital Asset Pricing: Empirical Anomalies Based on Earnings, Yields, and Market Values," *Journal of Financial Economics*, March 1981, pp. 19-46.

[12] Fama, Eugene F., and Kenneth R. French, "The CAPM is Wanted, Dead or Alive," *The Journal of Finance*, Vol. LI, No. 5, pp. 1947-1958.

[13] Chapter 7: Firm Size and Return, "Ibbotson Associates' Stocks, Bonds, Bills, and Inflation: 2006 Yearbook Valuation Edition," edited by James Harrington and Michael Barad, p. 129.

To account for this empirical bias against smaller companies, Ibbotson Associates has prescribed quantitative adjustments to the CAPM, which it publishes in the same data source used by many analysts to estimate the risk premium in their CAPM analyses.

Q. DID YOU APPLY THE ADJUSTMENT RECOMMENDED BY IBBOTSON ASSOCIATES IN YOUR ANALYSIS?

A. Yes. In my CAPM analysis, I followed the method recommended by Ibbotson Associates to compensate for this inherent data bias.

Q. HAVE ANY REGULATORY COMMISSIONS ACCEPTED THIS SIZE ADJUSTMENT TO THE CAPM IN RATE PROCEEDINGS WHEN DETERMINING THE COST OF COMMON EQUITY?

A. Yes. The Minnesota Public Utilities Commission has done so in an Interstate Power and Light Company case. The Commission observed:

> The Administrative Law Judge takes comfort from the fact that Ibbotson Associates is a widely-recognized statistical reporting firm that has a national reputation. He considers it to be in the same general category as Standard & Poor's or Moody's. There is no indication that the report in question was prepared for IPL, or the utility industry, to bolster arguments in rate cases. Instead, it appears that the report in question is part of an almanac-type yearbook that Ibbotson prepares without any particular focus on the utility industry. The Administrative Law Judge understands and shares the concerns of the Staff concerning the methodology used, and thinks the issue is worthy of pursuit in some other forum. But for purposes of this case, the Administrative Law Judge accepts the principal conclusion of the study – that size of a firm is a factor in determining risk and return.[14]

Q. PLEASE DESCRIBE THE RESULTS OF YOUR CAPM ANALYSIS.

A. My two CAPM studies provide comparative calculations, based on slightly different assumptions. In this way, they serve as benchmark comparisons to the DCF analysis that

[14] *In the Matter of the Petition of Interstate Power and Light Company for Authority to Increase its Electric Rates in Minnesota,* Docket No. E-001/GR-03-767, p. 7.

I had developed previously. Schedules DAM-23 and DAM-243 show the results of my CAPM analyses. Of course, because it is a risk premium analysis, I was able to estimate the cost of common equity of Aquila, Inc. in the current market. The results of the CAPM for Aquila, Inc. were 17.54 percent and 18.66 percent in current markets. However, as I mentioned previously, Aquila, Inc., is now essentially a regulated utility, but the recent restructuring still strongly influences its market-measured capital costs at this time. For this reason the averages of the CAPM results for the comparable LDCs of 12.68 percent and 12.98 percent are more reliable estimates of the cost of capital of Aquila for ratemaking in this proceeding.

Q. HAVE YOU PREPARED A SUMMARY OF THE RESULTS OF YOUR DCF AND CAPM ANALYSES?

A. Yes. Schedule DAM-25 illustrates a summary of the DCF and CAPM results. As I noted previously, the high end of the DCF results are the most reliable, and the averages for the comparable companies are 9.99 percent and 10.57 percent. The CAPM results for the comparable companies are 12.68 percent and 12.98 percent. As I noted previously, I believe that the 17.54 percent and 18.66 percent CAPM results for Aquila, Inc. are higher than necessary for ratemaking in this proceeding.

INTERPRETING THE DCF AND CAPM RESULTS

Q. WHAT DID YOU CONSIDER WHEN YOU INTERPRETED YOUR DCF AND CAPM RESULTS FOR THIS PROCEEDING?

A. I considered the recent and forecasted interest rates, returns on alternative investments, the actual returns to common stock of the comparable LDCs, the identifiable risks of Aquila and the limitations and biases of the DCF and CAPM methods.

Q. HOW ARE INTEREST RATES IMPORTANT TO YOUR INTERPRETATION OF THE DCF AND CAPM RESULTS?

A. Significantly, the levels of interest rates are a measure of the return that investors in utility equities might expect from alternative investments. Consequently, rising interest rates mean that investors will require higher returns from their common stock investments. Relatively speaking, if the risk premium between common stock and debt remains relatively constant, the returns to common stock investments must necessarily increase to attract and maintain capital, and this is an important consideration when establishing an allowed return. Additionally, utilities are capital intensive. Rising inflation and rising interest costs erode the earnings of utilities to a relatively greater extent than industrial companies and therefore are of greater concern to utility investors.

Q. YOU MENTIONED THE ACTUAL RETURNS OF THE COMPARABLE LDCS. WHAT ARE THE CURRENT AND FORECASTED RETURNS OF COMMON STOCK OF THE COMPARABLE LDCS?

A. The average return on common equity of the comparable LDCs in 2006 *Value Line* estimates will range between 9.5 percent for Southwest Gas and 16.0 percent for New Jersey Resources. The average for the group is 11.8 percent. During the 2009-11 period, *Value Line* estimates that the average for the groups' common stock returns will increase to 11.8 percent. I have shown these *Value Line* estimates in Schedule DAM-26.

Q. WHAT OTHER MARKET EVIDENCE DID YOU REVIEW ABOUT RETURNS TO COMMON EQUITY IN ORDER TO PUT YOUR CAPM AND DCF ESTIMATES IN A CURRENT MARKET CONTEXT?

A. I reviewed the recent returns to common stock of some non-regulated industries to view returns to alternative equity investments. I illustrate some of these data in Schedule DAM-27. Although, as expected, the range in recent and expected earnings varies considerably, these data are difficult to interpret. However, one characteristic is relatively similar and important. For the most part, these non-regulated industries are experiencing an increase in common equity returns.

Q. YOU PREVIOUSLY DISCUSSED AN INCREASE IN BUSINESS RISK BECAUSE OF HIGH NATURAL GAS PRICES. HOW DO HIGH GAS PRICES INCREASE THE BUSINESS RISK TO INVESTORS OF AN LDC?

A. High natural gas prices create demand risk for the LDCs and their investors. That is, high prices cause customers to adjust their consumption patterns and LDCs' sales volumes will fall short of levels upon which regulators determined the tariffs. At higher prices, customers reduce their natural gas consumption, install more efficient equipment, and switch to alternative fuels. In addition, high natural gas prices will deter some new customers from even connecting to natural gas utility service. This reduction in gas volumes sold means that LDCs will not earn expected, allowed returns based on larger, anticipated volumes. Investors perceive this threat to projected returns as a business risk. High gas prices also cause receivables to increase. These reduced margins decrease returns to levels less than those anticipated by the allowed returns set by regulators. To investors this increases uncertainty and is a business risk.

<u>RECOMMENDED RETURN</u>

Q. FROM YOUR CAPM ANALYSIS OF AQUILA, INC. AND THE COMPARABLE COMPANIES, YOUR DCF OF THE COMPARABLE COMPANIES, THE

CURRENT COST OF CAPITAL AND ALTERNATIVE RETURNS, HOW DID YOU DETERMINE A RECOMMENDED RETURN FOR AQUILA IN THIS PROCEEDING?

A. As I noted, the CAPM estimates for Aquila, Inc., although it is now principally a regulated utility, are higher than necessary for ratemaking because of the market-effects of the capital restructuring. The CAPM results for the comparable LDCs by two different, confirming methods are very similar. These are 12.68 percent and 12.98 percent.

The DCF results for the comparable companies are very sensitive to assumptions about the current market, and they do not represent the relative risks of Aquila. Probably the actual returns of the comparable LDC group are very significant for ratemaking in this instance. This is a measure of the returns for similar investments in utilities in similar businesses. This group should earn an average return on common stock in 2006 of 11.8 percent according to *Value Line*. In light of rising interest rates, I recommend that the allowed return for Aquila Networks - Nebraska be set in the range of 11.75 percent to 12.25 percent. Because of the uncertainties of the cost of raising capital to support utility service going forward, I believe that from the mid-point of this range, or 12.0 percent, to the upper end of the range, or 12.25 percent, is necessary for Aquila to attract capital in the current market. Looking at my recommendation from the perspective of investing in comparable LDCs, Aquila must at least be able to provide the same returns to existing and prospective common equity holders as its peer LDCs. That is precisely what the group of comparable companies represents, and my recommendation is in line with their current and forecasted earnings on common stock.

Q. WHAT IS THE TOTAL COST OR CAPITAL THAT YOUR RECOMMENDED ALLOWED RETURN ON COMMON EQUITY REPRESENTS?

A. At the 12.0 percent on common stock for Aquila Networks - Nebraska, which I recommend as a minimal return, will produce a total cost of capital of 9.60 percent. The upper end of my range, or 12.25, percent will result in a total cost of capital of 9.73 percent. I have illustrated this total cost of capital in Schedule DAM-28.

FINANCIAL INTEGRITY TEST

Q. YOU STATED PREVIOUSLY THAT YOU TESTED THE ADEQUACY AND APPROPRIATENESS OF YOUR RETURN RECOMMENDATION. HOW DID YOU TEST YOUR RECOMMENDED ALLOWED RETURN FOR AQUILA FOR ITS ADEQUACY AND APPROPRIATENESS?

A. As a direct measure of the financial integrity of my recommended allowed return range, I compared the After-Tax Interest Coverage ratios of Aquila at the high end and middle of this range to the coverages of the comparable LDCs. The After-Tax Interest Coverage is a measure that implies the likelihood that Aquila will have sufficient funds available to meet its fixed interest obligations should it earn at my recommended allowed return. The higher the coverage ratio the greater the likelihood that the allowed return will provide funds to meet the fixed interest obligations. Of course, because of the various business risks that can occur, the Company has no guarantee that it will earn this return. If it does earn at this level, this measure will show how its interest coverage will compare to the comparable LDCs. For my analysis, I simply determined if my recommended allowed return would result in interest coverage similar to the comparable LDCs.

Q. ASSUMING AQUILA ACHIEVES YOUR RECOMMENDED ALLOWED RETURN, HOW WOULD THE AFTER-TAX INTEREST COVERAGE RATIO FOR AQUILA COMPARE TO THE COVERAGES OF THE COMPARABLE LDCS?

A. The After-Tax Interest Coverage ratio of Aquila that would result from the minimal recommended allowed return on common equity of 12.0 percent is just 2.73 times. By comparison, the average After-Tax Interest Coverage of the comparable companies is a much higher and less risky coverage of fixed interest obligations of 3.62 times. Only Southwest Gas would have interest coverage lower than Aquila at my recommended return level. By any measure, the coverage of my minimally recommended allowed return is extremely low.

Q. DID YOU DETERMINE THAT THE UPPER END OF YOUR RECOMMENDED ALLOWED RETURN WOULD PROVIDE AN AFTER-TAX INTEREST COVERAGE THAT IS CLOSER TO THE COVERAGE LEVELS OF THE COMPARABLE LDCS?

A. If Aquila earns at the upper end of my recommended allowed return, this will do effectively reduce the measured coverage risk of Aquila *vis-a-vis* the comparable LDCs. Even at the upper-end of my recommended range, the After-Tax Interest Coverage is still only 2.77 times. Consequently, a return at the upper end of my recommended allowed return range will not move Aquila above the low end of the coverages of the comparable LDCs. This test confirms that my recommendation is very conservative, especially in the light of the uncertainty that Aquila can or will actually achieve this allowed return.

Q. HAVE YOU PREPARED A SUMMARY OF THESE COMPARATIVE INTEREST COVERAGE RATIOS AT THIS ALTERNATIVE RETURN LEVEL?

A. Yes. I have prepared a comparison of these interest coverage rations which I have illustrated in Schedule DAM-29.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

BEFORE THE NEBRASKA PUBLIC SERVICE COMMISSION

In the Matter of Aquila, Inc.,	)	
d/b/a Aquila Networks ("Aquila")	)	
seeking a general rate increase	)	Docket No.
for Aquila's Rate Areas One, Two	)	
and Three (not consolidated)	)	

Direct Testimony of Donald A. Murry, Ph.D.

Vice President
C.H. Guernsey & Company

Cost of Capital

October, 2006

Donald A. Murry
5555 N. Grand Blvd.
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DIRECT TESTIMONY OF

DONALD A. MURRY

<u>POSITION AND QUALIFICATIONS</u>

Q. PLEASE STATE YOUR NAME.

A. My name is Donald A. Murry.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am a Vice President and economist with C. H. Guernsey & Company. I work out of the Oklahoma City office and the Tallahassee office. I am also a Professor Emeritus of Economics on the faculty of the University of Oklahoma.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I have a B. S. in Business Administration, and a M.A. and a Ph.D. in Economics from the University of Missouri - Columbia.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A. From 1964 to 1974, I was an Assistant and Associate Professor and Director of Research on the faculty of the University of Missouri - St. Louis. For the period 1974-98, I was a Professor of Economics at the University of Oklahoma, and since 1998 I have been Professor Emeritus at the University of Oklahoma. Until 1978, I also served as Director of the University of Oklahoma's Center for Economic and Management Research. In each of these positions, I directed and performed academic and applied research projects related to energy and regulatory policy. During this time, I also served on several state and national committees associated with energy policy and regulatory matters, published and presented a number of papers in the field of regulatory economics in the energy industries.

Q. WHAT IS YOUR EXPERIENCE IN REGULATORY MATTERS?

A. I have consulted for private and public utilities, state and federal agencies, and other industrial clients regarding energy economics and finance and other regulatory matters in the United States, Canada**,** and other countries. In 1971-72, I served as Chief of the Economic Studies Division, Office of Economics of the Federal Power Commission. From 1978 to early 1981, I was Vice President and Corporate Economist for Stone & Webster Management Consultants, Inc. I am now a Vice President with C. H. Guernsey & Company. In all of these positions I have directed and performed a wide variety of applied research projects and conducted other projects related to regulatory matters. I have assisted both private and public companies and government officials in areas related to the regulatory, financial**,** and competitive issues associated with the restructuring of the utility industry in the United States and other countries.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE OR BEEN AN EXPERT WITNESS IN PROCEEDINGS BEFORE REGULATORY BODIES?

A. Yes, I have appeared before the U.S. District Court-Western District of Louisiana, U.S. District Court-Western District of Oklahoma, District Court-Fourth Judicial District of Texas, U.S. Senate Select Committee on Small Business, Federal Power Commission, Federal Energy Regulatory Commission, Interstate Commerce Commission, Alabama Public Service Commission, Alaska Public Utilities Commission, Arkansas Public Service Commission, Colorado Public Utilities Commission, Florida Public Service Commission, Georgia Public Service Commission, Illinois Commerce Commission, Iowa Commerce Commission, Kansas Corporation Commission, Kentucky Public Service Commission, Louisiana Public Service Commission, Maryland Public Service Commission, Mississippi Public Service Commission, Missouri Public Service

Commission, Nebraska Public Service Commission, New Mexico Public Service Commission, New York Public Service Commission, Power Authority of the State of New York, Nevada Public Service Commission, North Carolina Utilities Commission, Oklahoma Corporation Commission, South Carolina Public Service Commission, Tennessee Public Service Commission, Tennessee Regulatory Authority, The Public Utility Commission of Texas, the Railroad Commission of Texas, the State Corporation Commission of Virginia, and the Public Service Commission of Wyoming.

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A. Aquila, Inc. ("Aquila, Inc.") retained me to analyze the current cost of capital and recommend a rate of return and capital structure that is appropriate for the Aquila Networks – Nebraska, a division of Aquila, Inc. In this testimony, I will also refer to Aquila Networks – Nebraska, as "Aquila" or the "Company" in this proceeding.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I am sponsoring an exhibit that I have attached to my testimony which includes Schedules DAM-1 through DAM-28.

Q. WAS THIS EXHIBIT PREPARED EITHER BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, it was.

SUMMARY OF TESTIMONY

Q. CAN YOU SUMMARIZE YOUR ANALYSIS AND TESTIMONY IN THIS CASE?

A. First, I studied the current economic environment, taking note especially of the recent economic expansion and the accompanying inflationary pressures. This environment, in turn, has caused the Federal Reserve to repeatedly raise interest rates, with the direct consequence of increasing utility capital costs generally. Moreover, this environment has created an atmosphere of anticipated, continued interest rate increases according to consensus forecasts.

For my analysis of the cost of capital of Aquila Networks - Nebraska, I considered the appropriate capital structure, the cost of debt, and the cost of common stock, and in the analysis of each of these factors the restructuring of Aquila, Inc., I identified a group of LDCs that provided a basis for analyzing the cost of capital of an LDC similar to Aquila Networks - Nebraska. For example, in my determination of the appropriate capital structure for ratemaking in this proceeding, I noted that the Aquila Networks - Nebraska divisional capital structure, which has a lower common stock equity ratio than the average of the group of LDCs that I studied, was appropriate. This is the permanent capital supporting Aquila's assets that provide the gas distribution service to the Nebraska customers. The appropriate cost of debt for this proceeding is the embedded cost of long-term debt of Aquila of 7.13 percent.

For the measurement of common stock equity of Aquila, I also relied extensively upon the measured costs of common equity of the comparable companies. The common, market-based Discounted Cash Flow ("DCF") method and Capital Asset Pricing Model ("CAPM") were useful for estimating the cost of the comparable utilities. I could not use the DCF to analyze the cost of common for Aquila, Inc. because of the recent history of negative earnings, no dividends and no forecasted dividends. I also reviewed the financial statistics of Aquila, Inc. and the comparable LDCs. Additionally, I noted that *Value Line* is predicting that the comparable companies will earn an average return on common stock in 2006 of 11.8 percent. *Value Line* also is predicting that the gas distribution sector will earn 12.0 percent on common stock equity in the period 2009 to 2011. As a comparison, *Value Line* predicts that Aquila, Inc. will again experience a loss in 2006 and for the fourth year will not pay a dividend.

To interpret the DCF and CAPM analyses, I also evaluated several specific business risk factors of Aquila Networks - Nebraska. Taking these risk factors into account I determined a recommended allowed return for Aquila in this proceeding. I am recommending an allowed return for the Company in this proceeding in the range of 11.75 to 12.25 percent, but I think that realistically the midpoint of this range, or 12.0 percent, is the minimal level necessary for Aquila to maintain an acceptable probability of acquiring capital. This common equity return results in a recommended return on total capital ranging between 9.60 percent and 9.73 percent.

I tested my recommended return to verify that it was sufficient to attract and maintain capable, and at the same time, to determine that my recommendation would not produce an excessive return to common stock holders. As a straight-forward measure, I compared the After-Tax Interest Coverage for Aquila at the higher end of my recommended return level is 2.77 times. This is much lower than the average coverage for the comparable utilities, which is 3.62 times, and lower than the coverage for all but one of the comparable utilities. From this comparison, it is apparent that my recommended allowed return for Aquila is conservative in current markets.

UTILITY REGULATION

Q. DID THE POLICIES AND PROCEDURES OF UTILITY REGULATION AFFECT YOUR COST OF CAPITAL TESTIMONY IN ANY WAY?

A. Yes. I based my analysis and recommendations on my interpretation of the role of regulation in the natural gas distribution industry. Because of the nature of the industry, analysts have recognized the likely presence of market power in a franchised utility market. Economies of scale at the distribution or retail level of utility service indicate that the duplication of facilities by more than one firm may be economically inefficient. This is the principal economic rationale for utility regulation, and I used this as a guide for my analysis and recommendations in this proceeding. Consequently, I predicated my analysis on the objective to set an allowed return in a regulatory proceeding that is sufficient to allow a utility to recover the costs of providing service, but not higher than necessary to attract and maintain invested capital that provides utility service. As an economist, I believe that these analytical objectives are consistent with the legal standard of a "fair rate of return" in regulation.

Q. WHAT DID YOU MEAN WHEN YOU MENTIONED THE "LEGAL STANDARD" THAT YOU USED TO MEASURE A "FAIR RATE OF RETURN?"

A. I am using the term "fair rate of return" in a manner that is consistent with my understanding of the return that meets the standards set by the United States Supreme Court decision in *Bluefield Water Works and Improvement Company vs. Public Service Commission, 262 U.S. 679 (1923) ("Bluefield")*, as further modified in *Federal Power Commission vs. Hope Natural Gas Company, 320 U.S. 591 (1944) ("Hope").* As I understand these decisions, they characterize a "fair rate of return" as one that provides earnings to investors similar to returns on alternative investments in companies of equivalent risk.

Q. AS AN ECONOMIST, WHAT IS YOUR INTERPRETATION OF THE TERM A "FAIR RATE OF RETURN"?

A. As I understand it, the term a "fair rate of return" means that a return is sufficient to enable a company to operate successfully, maintain its financial integrity, attract capital on reasonable terms, and compensate investors for the risks associated with the provision of natural gas service. Throughout my analysis, I was very sensitive to both the financial and business risks of Aquila in providing gas distribution service in Nebraska.

ECONOMIC ENVIRONMENT

Q. WHAT DID YOU DETERMINE ARE THE CURRENT ECONOMIC FACTORS THAT ARE IMPORTANT FOR SETTING THE COST OF CAPITAL IN THIS PROCEEDING?

A. The key factors in the current economic environment that affect investors are expectations regarding inflation and interest rates. Forecasts of inflation and interest rates affect investors' expectations of returns and their evaluations of the risks and returns on alternative investments. For these reasons, I reviewed both the current and forecasted levels of inflation and interest rates.

Q. WHAT ABOUT THE CURRENT ECONOMIC ENVIRONMENT DID YOU FIND IMPORTANT FOR YOUR ANALYSIS OF THE COST OF CAPITAL IN THIS PROCEEDING?

A. Entering the third quarter of 2006, economic activity is continuing to expand, although at a decelerating rate. As shown on Schedule DAM-1, the consensus forecast, as provided by *Blue Chip Financial Forecasts ("Blue Chip"),* predicts real GDP growth of 2.6 percent in the third and fourth quarter of 2006 and 2.7 percent for the first half of 2007.

The economy is also showing signs of increasing inflation after several years of stable prices. The consensus forecast for December-over-December core Consumers' Price Index ("CPI") growth (which excludes food and energy costs) is 2.6 percent for 2006. The Federal Open Market Committee ("FOMC"), in the minutes from its August 8, 2006 Committee Meeting, stated:

> Headline inflation continued to move up, on balance, in recent months, and consumer prices increased at a faster pace in the second quarter than over the previous twelve months. Consumer energy prices, while declining slightly in June, surged during the second quarter, on net. Core consumer prices also continued to rise, boosted by an acceleration in shelter costs, particularly those for owner-occupied residences, and some pass-through of energy cost increases. Higher oil prices showed through in producer prices for a variety of energy-intensive intermediate goods. Rising import prices, higher domestic rates of capacity utilization, and strong global demand for materials were factors underlying an acceleration in core prices for intermediate materials.

Q. YOU MENTIONED INFLATION LEVELS. CAN YOU ELABORATE UPON RECENT AND FORECASTED INFLATION RATES, AND WHY THEY WERE IMPORTANT TO YOUR ANALYSIS?

A. The Consumer Price Index increased 0.2 percent in August 2006 following a 0.4 percent increase in July. Core CPI increased 0.2 percent in August for the second consecutive month. The expected 2.8 percent rate of core inflation for 2006 is almost double that of the 1.5% rate of three years ago. This large increase reveals a broadening of inflationary pressures in the economy. As shown in Schedule DAM-1, *Blue Chip* is forecasting the CPI to increase in a range between 2.6 percent and 3.4 percent for the remainder of 2006. Increasing inflationary pressures are troubling to the financial markets and have the full attention of Federal policymakers. On August 22nd, Chicago Federal Reserve President Michael Moskow cautioned, "More rate hikes may still be necessary to cut inflation."

And as cited by *Blue Chip*[1], he also indicated that the risks is more toward inflation being too high than growth being too low.

Manufacturing activity is continuing to increase nationwide, putting pressure on the labor markets while health care and post-retirement costs continue to be a concern. Consumer spending, which accounts for two thirds of economic activity, has been increasing, albeit slowly, weighted down by sluggish sales of autos and housing related goods. Housing markets and construction activity are softening throughout the country, at least in part because of rising interest rates. Schedule DAM-2 illustrates the historical trends of GDP growth, unemployment and inflation statistics, and these statistics, which reveal the inflationary pressures, are examples of what the Federal Reserve evaluates when considering monetary policy.

Q. HOW HAS THIS ECONOMIC ACTIVITY AFFECTED INTEREST RATES?

A. The state of the economy and economic expectations are important background for my cost of capital analysis because increasing inflationary pressures almost certainly lead to actions by the Federal Reserve to increase interest rates. For example, the Federal Open Market Committee has raised interest rates 17 times since June 2004. Although the FOMC recently has forgone raising short-term rates, it has indicated it will remain vigilant regarding inflation concerns. In its August 8, 2006 press release[2], the FOMC stated:

> …the Committee judges that some inflation risks remain. The extent and timing of any additional firming that may be needed to address these risks will depend on the evolution of the outlook for both inflation and economic growth, as implied by incoming information.

[1] *Blue Chip Financial Forecasts*, September 1, 2006.
[2] Federal Reserve Release, August 8, 2006.

Q. CAN YOU SUMMARIZE WHAT YOU FOUND TO BE THE SIGNIFICANT INTEREST RATE DEVELOPMENTS?

A. As the economy expands, the Federal Reserve has signaled it will raise interest rates as necessary to keep inflation at bay. Regarding the outlook for inflation and Federal Reserve action, the Richmond Federal Reserve Bank President, Andrew Lacker, recently described the inflation outlook as, "…borderline acceptable and perhaps even beyond." Fed Chairman Ben Benanke also has stated, "there are some upside inflation risks in the economy" and "…some additional firming of policy might yet be needed."

Q. DID YOU STUDY THE RECENT AND FORECASTED BOND RATES?

A. Yes. Bond prices have decreased substantially in 2006, thereby raising yields on bonds to their highest level since 2002. As shown on Schedule DAM-3, the 10-year Treasury Bond and the Aaa-corporate rate are currently about 5.0 percent and 5.8 percent, respectively. Most significantly, as shown in Schedule DAM-4, analysts expect long-term bond rates to continue rising. The *Value Line* forecasts for the Baa-corporate rate and the 10-year Treasury rate are for continuing increases to 6.7 percent and 5.5 percent respectively through 2009.

Q. WHY ARE THESE ECONOMIC CONDITIONS IMPORTANT TO THIS PROCEEDING?

A. The rates set in this proceeding will be in effect during a period of rising inflation and interest rates. Because of its restructuring and capital requirements, Aquila, Inc. will be in the market to acquire permanent capital to support continued and expanded utility service during this period. Also, rising inflation and interest rates adversely affect the cost of a gas utility's debt, and the combination of the high cost short-term debt--which funds natural gas purchases--and high natural gas prices significantly increases business risk to investors. This increases the risk to common stockholders that they will achieve their anticipated returns on investment.

SELECTION OF COMPARABLE COMPANIES

Q. WHAT CRITERIA DID YOU USE TO SELECT THE UTILITIES THAT YOU IDENTIFIED AS COMPARABLE TO AQUILA NETWORKS - NEBRASKA FOR YOUR ANALYSIS?

A. I selected a group of local gas distribution utilities for comparative analysis that have typical risks that healthy LDCs face. I first selected the comparable companies from a group of gas distribution companies reported by *Value Line.* Second, because of the importance of size in determining the cost of capital of a utility, I limited the group of distribution companies to firms with a market capitalization of less than $2 billion. Third, I excluded companies that do not pay a dividend. Fourth, I eliminated those companies that are not primarily gas distributors, and finally, I dropped LDCs that are actively involved in a merger.

Q. WOULD YOU EXPLAIN WHY YOU DID NOT USE AQUILA, INC.'S FINANCIAL CRITERIA TO SELECT A GROUP OF COMPARABLE COMPANIES FOR YOUR ANALYSIS?

A. Aquila, Inc. is still in the process of restructuring itself to a utility-only business. Selecting companies with similar financial characteristics to a financially viable utility provides a benchmark for comparison and aids in the interpretation of the statistics of Aquila Networks - Nebraska. Methodologically, I used this set of comparable companies as a representative "sample" of the gas distribution sector and, by inference, representative of the cost of capital of a utility with these financial characteristics. For this reason, it is important to determine the risks and the associated costs of common stock equity of gas distribution utilities that are similar to Aquila Networks – Nebraska. I selected this group of companies by holding some key characteristics constant when I selected the companies for comparison. Using a group of comparable companies analytically is also consistent with the regulatory objective of determining the cost of investing in securities of equivalent risks.

Q. WHAT COMPANIES DID YOU SELECT AS COMPARABLE TO AQUILA NETWORKS - NEBRASKA AND THEREFORE SUITABLE FOR YOUR ANALYSIS?

A. Using the set of criteria mentioned above, I determined that eight primarily natural gas companies were similar in key respects to Aquila Networks - Nebraska. This group includes: Laclede Group, New Jersey Resources, NICOR, Inc., Northwest Natural Gas, Piedmont Natural Gas, South Jersey Industries, Southwest Gas and WGL Holdings, Inc.

<u>CAPITAL STRUCTURE</u>

Q. WHAT IS THE APPROPRIATE CAPITAL STRUCTURE FOR AQUILA NETWORKS - NEBRASKA IN THIS PROCEEDING?

A. As I have illustrated in Schedule DAM-5, the Company has a total capitalization of $273,050,946 at June 30, 2006. The Long-Term Debt is $134,540,892, or 49.27 percent of total capital, and the Common Equity is $138,510,054 or 50.73 percent of total capital.

Q. YOU DID NOT INCLUDE ANY SHORT-TERM DEBT IN THIS CAPITAL STRUCTURE THAT YOU ARE RECOMMENDING FOR AQUILA NETWORKS

- NEBRASKA. WHY DID YOU EXCLUDE SHORT-TERM DEBT IN YOUR RECOMMENDED CAPITAL STRUCTURE?

A. I only included components of capital in the capital structure that are part of the permanent capital that supports physical utility assets providing utility services currently and during the period that the rates set in this proceeding will be in effect.

Q. IS THIS CAPITAL STRUCTURE THAT YOU ARE RECOMMENDING IN THIS PROCEEDING, THE CURRENT CAPITAL STRUCTURE OF AQUILA, INC.?

A. No. The restructuring of Aquila, Inc., which includes the sale of non-domestic investments and most non-regulated businesses, has affected significantly its current capital structure. Because this restructuring has been on-going, the current capital structure is a carry-over from a prior more diverse company. This is less representative of a LDC capital structure than the divisional capital structure of Aquila Networks - Nebraska. For example, Aquila, Inc. is still in the process of moving proceeds from the sales of various businesses to pay down outstanding debt, and the capital structure is not representative of the permanent capital that supports the utility service in Nebraska.

Q. HOW DOES THE CURRENT CAPITAL STRUCTURE OF AQUILA, INC. COMPARE TO THE CAPITAL STRUCTURE OF A TYPICAL LDC?

A. As I illustrate in Schedule DAM-6, according to *Value Line,* Aquila, Inc.'s current common equity ratio is only 43 percent. This is a lower common equity ratio than all of the comparable LDCs except Southwest Gas. Aquila, Inc.'s common equity ratio is also much lower that the average common stock equity ratio for the group of comparable LDCs, which is 54.7 percent. Notably, *Value Line* is also predicting, that following the present restructuring, that Aquila, Inc.'s common equity ratio will be 53.5 percent in the

2009-11 time period. This is closer to the common equity ratio of a regulated LDC in current markets, and it provides further evidence that the current, low common equity during this period of restructuring is not appropriate for setting rates of Aquila Networks - Nebraska. Of course, it is also important that the rates set in this proceeding are likely to run, at least, into the forecast period.

Q. DID YOU STUDY THE CHANGES IN AQUILA, INC.'S COMMON EQUITY RATIO IN RECENT YEARS?

A. Yes. As Schedule DAM-7 shows, I compared Aquila, Inc.'s growth in common stock outstanding, as reported by *Value Line*, to the growth of common stock outstanding of the comparable LDCs. Obviously, Aquila, Inc.'s growth in common stock outstanding has been much higher than any of the comparable distribution utilities during this period. This is not surprising, however, because Aquila, Inc.'s restructuring has required a de-leveraging of its balance sheet. This makes the issuance of common stock a more attractive vehicle to acquire the capital needed for plant expansion and to reduce debt.

Q. FROM YOUR ANALYSIS OF THE COMPANY, DO YOU BELIEVE THAT THE COMMON EQUITY RATIO OF AQUILA, INC. WILL APPROACH THE LEVEL PREDICTED BY *VALUE LINE?*

A. Yes. As Aquila, Inc.'s restructuring leads to primarily utility operations, it is only logical that analysts would expect the company to acquire a capital structure that is characteristic of that industry sector.

COST OF LONG-TERM DEBT

Q. FROM YOUR ANALYSIS, WHAT IS THE APPROPRIATE COST OF LONG-TERM DEBT FOR AQUILA IN THIS PROCEEDING?

A. As shown in Schedule DAM-8, the weighted average cost of long-term debt that is appropriate for Aquila in this proceeding is 7.13 percent. This is the cost of long-term debt that Aquila, Inc. used to acquire the long-term assets that provide utility service to Nebraska customers. This, however, is a conservative cost of long-term debt because of Aquila, Inc.'s policy of assigning investment grade costs to debt issues in order to protect ratepayers from the capital costs of the non-regulated businesses.

FINANCIAL RISK

Q. YOU STATED PREVIOUSLY THAT YOU INVESTIGATED THE "FINANCIAL RISK" OF AQUILA. WHAT DO YOU MEAN BY THE TERM FINANCIAL RISK?

A. Financial risk to the common stock holders of a company is the risk that they incur because the claims of the debt instruments must be paid prior to any returns accruing to common stock. In general, the lower the common stock equity ratio, the greater is the relative, prior obligation owed to debt holders. Consequently, all things equal, the risk faced by holders of a company's common stock is greater if the common equity ratio is smaller.

Q. IS FINANCIAL RISK AN IMPORTANT CONSIDERATION IN THIS PROCEEDING?

A. Yes. Financial risk is an important determinant of the required return. It is especially important in this proceeding because of the differential between the common equity ratios of the parent Aquila, Inc. and the operating division, Aquila Networks - Nebraska. Notably, the average common equity ratio of the comparable companies of 54.7 percent is higher than the common equity component of the Aquila Networks - Nebraska.

Q. DID YOU COMPARE THE FINANCIAL RISK OF AQUILA, INC. TO THAT OF A TYPICAL LDC?

A. Yes. I think that one can reveal the relative financial risk of Aquila, Inc. by comparing some of its credit measures to similar measures for the comparable LDCs. I have illustrated this comparison in Schedule DAM-9 using *Value Line's* measure of "Financial Strength" And Standard & Poor's "Credit Rating." *Value Line* ranks Aquila, Inc. a "C", placing it in the group second from the bottom of all companies that *Value Line* ranks. None of the comparable LDCs have a financial strength rating that low, and only Southwest has a rating as low as a "B" which is average for all companies that *Value Line* follows. *Value Line* rates four of the gas distribution companies as "A". Also, as that schedule shows, Standard & Poor's rates Aquila, Inc.'s credit a B, which is four levels below investment grade. All of the other gas utilities have investment grade credit ratings of "BBB" or above and six of the eight are "A" rated or above. As noted previously, greater financial risk means that in order to invest, investors will look for higher compensating common stock returns. Consequently, by using the capital structure of the operating division in Nebraska in this proceeding to determine the allowed returns, I can use the estimated cost of the comparable LDCs as a guide for determining a recommended allowed return because the capital structure of the operating division in Nebraska is closer to the industry norm.

<u>BUSINESS RISK</u>

Q. YOU ALSO STATED THAT YOU INVESTIGATED THE "BUSINESS RISK" OF AQUILA. HOW DID YOU DEFINE BUSINESS RISK?

A. Business risk is the exposure of the returns to common stockholders resulting from the vagaries of business operations. In many respects, the most important business risks for LDCs are: competition from other fuels, local economic conditions, rising gas costs that reduce sales, the impact of rising inflation and interest rates, and any uncertainty with the recovery of the costs of purchased gas. High gas costs, for example, lead to increased working capital and short-term debt requirements needed to pay suppliers until the LDC recovers gas costs through rates. The rising short-term interest rates further exacerbate the situation. Furthermore, LDCs face rising, unanticipated bad debt expenses and accounts receivable in these markets. In my analysis, I considered these and other general business risks.

Q. DO YOU BELIEVE THAT BUSINESS RISK IS AN IMPORTANT CONSIDERATION IN THIS PROCEEDING?

A. Yes. Business risk is also a prime determinant of the required rate of return. The business risks that I have described above are risk factors that are common to the natural gas industry, and Aquila Networks - Nebraska undoubtedly faces similar business risks.

Q. DID YOU DETERMINE ANY MEASURES OF BUSINESS RISK THAT PERTAIN SPECIFICALLY TO THE OPERATIONS OF AQUILA, INC.?

A. Yes. I reviewed several indices of business risk of Aquila, Inc. as reported by financial analysts, which I reported in Schedule DAM-10. Although these measures in some respects combine financial and business risks together as a common measure, they are likely to be closer to business risk than the credit measures mentioned previously. I compared the measures for Aquila, Inc. with those for the group of comparable companies.

Q. ARE YOU AWARE IF AQUILA NETWORKS – NEBRASKA HAS SOME OF THE RISKS THAT AFFECT THE LDC SECTOR?

A. Yes. This is clearly the case. It appears that declining use per customer, in many instances is similar in Nebraska to other parts of the country; customers' switching to heat pumps is one cause. Also, declining population in some areas of the system also is an added risk.

A more important, and somewhat unusual, factor is the competition in the area in and around Omaha. As I understand the competitive situation for Aquila Networks – Nebraska, it does not have a certificated service territory in this area. This is, of course contrary to the economic rationale for regulation that I discussed previously. That is, traditionally a certificated service territory is the conceptual justification for regulation and lower capital costs for an LDC because it precludes direct competition and this lowers risks to investors. Consequently, this is evidence that Aquila Networks - Nebraska has more business risk exposure than the typical LDC.

Q. YOU IDENTIFIED ADDITIONAL RISK MEASURES OF AQUILA, INC. WHAT DID THESE ADDITIONAL MEASURES OF RISK SHOW?

A. These measures also show very clearly the sharp risk distinction between Aquila, Inc. and the comparable LDCs. I have illustrated several key statistics from *Value Line* and Standard & Poor's in Schedule DAM-10. As this schedule shows very clearly, analysts view Aquila, Inc. quite differently from the selected LDCs in the current markets. Using *Value Line* measures of "Safety", "Price Stability", "Price Growth" and "Earnings Predictability," analysts will perceive Aquila, Inc.'s common stock to be a much more risky investment than the common stock of the other, comparable LDCs. For example, the "Safety" rank is "a measurement of potential risk associated with individual common stocks. The value shows where an individual stock is in relation to the entire universe of Value Line's stocks.[3]" Stocks ranked 1 (Highest) and 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) and 5 (Lowest) are likely to underperform most stocks over the next 12 months. Aquila, Inc. is rated a "5". The lowest ranking of the comparable LDCs is a "3". Also, in its "Business Profile", Standard & Poor's ranks Aquila, Inc. an "8" which is distinctively much more risky than any of the comparable LDCs, which average only a "2.4".

Q. ARE YOU AWARE OF ANY OTHER SPECIFIC BUSINESS RISKS THAT MAY BE UNIQUE TO AQUILA NETWORKS - NEBRASKA?

A. One business risk factor that could be important for ratemaking going forward is the effect of Aquila, Inc.'s recent restructuring. Of course, economies of scale are one of the benefits of company size, and this has been a driving factor in the mergers and acquisitions in the natural gas distribution sector in recent years. As Aquila, Inc. has disposed of several operating companies in recent years, the reallocation of centralized costs over a smaller customer and utility plant base could be a risk to common stock holders. That is, if the allocation of these costs reduces the likelihood of their recovery, this is a risk to common equity of Aquila Networks - Nebraska.

Q. IN YOUR OPINION, HAS THIS RESTRUCTURING INCREASED THE RISK TO THE COMMON EQUITY OF AQUILA NETWORKS - NEBRASKA?

A. No, I believe that the restructuring has not increased the cost of common equity of Aquila Networks - Nebraska. In fact, as Schedule DAM-11 shows, the Operations & Maintenance Expenses per Customer and the Net Plant per Customer for Aquila

[3] "How to Invest in Common Stocks: The Complete Guide to Using the Value Line Investment Survey," (2003: Value Line Publishing, Inc., New York), p. 41.

Networks – Nebraska are within the range of my comparable companies. Of course, these metrics may require further interpretation; utilities with a more concentrated service territory may have lower costs per customer than more rural systems. Consequently, I also compared Aquila Networks – Nebraska to Kinder Morgan - Nebraska. This comparison also demonstrates that the restructuring of Aquila, Inc. has not adversely affected the cost per customer of Aquila Networks – Nebraska and increased the risks to common equity.

Q. FROM A RATEMAKING STANDPOINT, SHOULD THE HIGHER RISK OF AQUILA, INC. INFLUENCE THE COST OF CAPITAL OF THE UTILITY OPERATING DIVISIONS?

A. Aquila, Inc. has tried to isolate the impact of the credit and risk problems of the parent from the regulated utility, and this is a sound policy in my opinion. Nonetheless, I think recognizing this risk differential is important as a background for this analysis of Aquila's cost of capital. For example, this sharp distinction in the risk of Aquila, Inc. and the comparable LDCs is further confirmation that Aquila, Inc.'s high risk capital structure is inappropriate for ratemaking for Aquila Networks – Nebraska in this proceeding.

Q. IN YOUR OPINION, SHOULD THIS RISK DIFFERENTIAL BETWEEN AQUILA, INC. AND THE TYPICAL LDCS CHANGE IN THE FUTURE?

A. In the future, as Aquila, Inc. evolves as a parent company of a group of regulated utilities, this risk differential noted by analysts should diminish. In fact, Aquila should experience the potential economies of scale that afford cost savings to an utility operating division of a larger company. Typically, a utility operating division flows those lower costs through to rates, and that is the potential inherent benefit in this structure. The mergers and combinations of utilities in recent years is evidence that it is an industry trend to seek these economies.

Q. WHEN YOU REVIEWED THE COMMON STOCK EARNINGS OF THE COMPANIES THAT YOU STUDIED, WHAT DID THIS SHOW?

A. The recent common stock losses of Aquila, Inc., which fortunately are improving, set it apart from the positive earnings and earnings growth of the group of comparable gas distribution utilities. I have shown this comparison in Schedule DAM-12. Similarly, comparing the percentage returns on common equity of Aquila, Inc. to the comparable utilities confirms this risk differential. For example, *Value Line* estimates the average return on common stock equity for this group of companies in 2006 at 11.8 percent, with a high for New Jersey Resources of 16.0 percent. With its financial difficulties, Southwest Gas, at a return to common equity of 9.5 percent, is the only one of these LDCs that has returns in the single digits. I have demonstrated this comparison in Schedule DAM-13.

Q. WERE AQUILA, INC.'S LOSSES AND LOW FORECASTED COMMON STOCK EARNINGS IMPORTANT TO YOUR ANALYSIS IN ANY OTHER WAYS?

A. Because analysts and investors are not anticipating a positive return from an investment in Aquila, Inc., this renders a meaningful DCF analysis of Aquila, Inc. using earnings growth rates impossible.

Q. WHEN YOU REVIEWED THE COMMON STOCK DIVIDENDS, WHAT DID YOU DETERMINE?

A. This comparison provided more evidence confirming the financial distinction between the comparable gas distribution utilities and Aquila, Inc. at this point in time. As I have illustrated in Schedule DAM-14, each of the comparable gas distribution utilities has paid a dividend in each of the last five years. This is in contrast to Aquila, Inc. which has not paid a dividend since 2002. Moreover, *Value Line* predicts that it will pay no dividends through the period 2009-11.

Q. IS IT IMPORTANT TO YOUR ANALYSIS THAT AQUILA, INC. HAS NOT PAID A DIVIDEND IN RECENT YEARS AND THAT *VALUE LINE* FORECASTS THAT IT WILL NOT PAY A DIVIDEND IN THE 2009-11 PERIOD?

A. Yes. Because analysts and investors are not anticipating a dividend from Aquila, Inc., analytical methods based on the near-term return on investment through dividends, such as the DCF, will not produce meaningful results.

<u>COST OF COMMON STOCK</u>

Q. YOU ALSO STATED PREVIOUSLY THAT YOU CALCULATED THE COST OF COMMON STOCK EQUITY FOR A COMPARABLE GROUP OF GAS DISTRIBUTION COMPANIES. WHAT METHODS DID YOU USE?

A. I used the two most common methods for estimating the cost of common stock in regulatory proceedings, the Discounted Cash Flow and the Capital Asset Pricing Model. The DCF analysis, which is probably the most commonly referenced method in regulatory proceedings, and the CAPM, which provides a longer-term perspective to the analysis compliment on another.

For comparative purposes, I set out to apply each of these methods to estimate the cost of common stock of Aquila, Inc. and each of the comparable companies. As a result of the sharp risk differentials observed previously, this comparison is important analytically. However, because of the difficulty in assessing the growth statistics of Aquila, Inc., the DCF of Aquila, Inc. estimates are not reliable. The CAPM for Aquila, Inc. incorporates the greater risk differential. Consequently, these results require interpretation in this context.

Of course, just mechanically applying either of these methods is a sterile analysis, so I investigated the assumptions underlying the methods in order to interpret the results if these assumptions remained satisfied in this case. I also reviewed academic literature related to the use of these two techniques. In this way, I interpreted the results in the context of their strengths and weaknesses of these methods, and, to put them into perspective, I evaluated these calculations in the context of current market conditions.

DISCOUNTED CASH FLOW METHOD

Q. YOU MENTIONED THAT YOU USED THE DCF METHOD FOR DETERMINING COST OF COMMON STOCK. CAN YOU DEFINE THE DCF METHODOLOGY FOR MEASURING COST OF COMMON EQUITY?

A. Yes. The DCF calculation of the investor's required rate of return can be expressed by the following formula:

$$K = D/P + g$$

Where:
- K = cost of common equity
- D = dividend per share
- P = price per share and
- g = rate of growth of dividends, or alternatively, common stock earnings.

In this expression K is the capitalization rate required to convert the stream of future returns into a current value.

Q. YOU MENTIONED THE UNDERLYING ASSUMPTIONS OF THE COST OF CAPITAL MODELS. WHAT ASSUMPTIONS UNDERLYING THE DCF METHOD ARE IMPORTANT WHEN ESTIMATING THE COST OF COMMON STOCK EQUITY IN PRACTICE?

A. As an example of underlying assumptions of the DCF, David Parcell stated in *The Cost of Capital—A Practitioner's Guide,*[4] that the general DCF model has the following four key assumptions:

> 1. Investors evaluate common stocks in the classical economic framework.
> 2. Investors discount the expected cash flows at the same rate (K) in every future period.
> 3. K corresponds only to the specific steam[sic] of future cash flows.
> 4. Dividends, rather than earnings, constitute the source of value.

These key assumptions are important; when not realized in practice, they can lead to incorrect measures of the cost of common equity. In turn, this may lead to misinterpretation of the results using the DCF method.

Q. WHAT DO YOU SEE AS STRENGTHS OF THE DCF METHOD?

A. I believe that its principal strength is its theoretically soundness. Recognizing that an investor expects a return on investment in the form of dividends and capital gains, the DCF implies that the investor is willing to pay a market price that is equal to the present value of that stream of earnings to acquire the common stock. Using these market relationships, an analyst can estimate the opportunity cost of an investor's funds, which is consistent with the regulatory objective of setting an allowed return equal to the returns to investments of equivalent risk. As a market-based measure recognizing investors' expectations, the DCF relates the market price information and the company's dividend

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[4] Parcell, David, *The Cost of Capital—A Practitioner's Guide,* Society of Utility and Regulatory Analysts, 1997, pp. 8-5, 8-6.

and earnings performance to determine the value that investors place on anticipated returns.

Another common advantage in regulation is that the DCF is the most common method analysts use to measure the cost of common equity in regulatory proceedings. Consequently, persons involved in regulatory proceedings are familiar with it.

WEAKNESSES OF THE DCF

Q. WHEN USED IN A UTILITY RATE PROCEEDING, WHAT DO YOU SEE AS IMPORTANT WEAKNESSES OF THE DCF METHOD?

A. The DCF has both conceptual and data issues that may lead to misinterpretation of the calculated results. Either or both can create problems in a ratemaking proceeding.

Q. YOU STATED THAT CONCEPTUAL PROBLEMS OF THE DCF MAY LEAD TO MISINTERPRETATION OF THE CALCULATED RESULTS. WHAT CONCEPTUAL PROBLEMS OF THE DCF MAY BE IMPORTANT WHEN AN ANALYST USES IT TO ESTIMATE THE COST OF CAPITAL IN A RATE PROCEEDING?

A. A significant problem of the DCF method which can lead to a misinterpretation in a rate proceeding is the very nature of the DCF method. The DCF estimates the marginal cost of common stock equity of a company, and often analysts applying the data do not recognize the theoretical significance of this. That is, the DCF provides an estimate of the minimal return necessary to attract marginal, or incremental, investment in the common stock equity. However, the method does not account for any other factors that may affect the ability of the company to earn that return.

Q. IN REGULATORY PRACTICE, WHY IS THE MARGINAL COST NATURE OF THE DCF SIGNIFICANT?

A. Analysts interpreting the results of the DCF calculations may not recognize their context or what they truly represent. Consequently, the DCF-based calculations may be misleading. For example, the DCF calculated cost of common equity result does not provide any cushion in the estimation of the cost of capital. When using these results as a basis for a recommended allowed return in a regulatory proceeding, the bare-bones calculations may not provide a regulated company a reasonable likelihood to earn its allowed return. In fact, this misunderstanding of the DCF results can virtually assure that a regulated company will not have the opportunity to earn its allowed return.

Q. IN YOUR EXPERIENCE IS IT COMMON FOR REGULATORS AND ANALYSTS TO RECOGNIZE THIS CHARACTERISTIC OF THE DCF METHOD?

A. Yes, it is. Regulators and analysts often apply adjustments to compensate for the marginal cost nature of the DCF adjustment. For example, some analysts specifically apply a flotation adjustment. The flotation adjustment specifically recognizes that the measurement of the market-based DCF estimate of the cost of capital does not always incorporate the costs of issuing common stock, i.e., legal fees, investment banker fees and publication costs of a prospectus. Some analysts also apply an adjustment for "market pressure" associated with the sale of securities. This also is a direct recognition that an analyst should recognize the effects of market activities not encompassed in the current DCF estimate when setting rates for a future time period.

Q. RECOGNIZING THE MARGINAL COST NATURE OF THE DCF AND THE NEED OF A REGULATED UTILITY TO BE ACTIVE IN THE FINANCIAL MARKETS, DO YOU RECOMMEND CALCULATING A FLOTATION ADJUSTMENT?

A. No, I believe that focusing on the high end of the DCF results is adequate compensation for the regulated utility, and I believe that these are results that fall within the distribution of estimated cost of common equity. This also provides market measured estimates of the cost of such factors as flotation costs and other market effects. This, in my opinion, directly recognizes the marginal cost nature of the DCF method.

Q. TO YOUR KNOWLEDGE, HAVE REGULATORY COMMISSIONS RECOGNIZED THESE LIMITATIONS OF THE DCF WHEN USED IN RATE PROCEEDINGS TO DETERMINE THE COST OF COMMON EQUITY?

A. Yes, commissions have recognized some of these difficulties. In one example addressing these factors directly, the Indiana commission in a 1990 decision recognized that the assumptions underlying the DCF model rarely, if ever, hold true.[5] This commission stated that an "…unadjusted DCF result is almost always well below what any informed financial analyst would regard as defensible and therefore requires an upward adjustment based largely on the expert witness' judgment."[6]

Q. HAVE ANALYSTS PERFORMED STUDIES REGARDING WHICH DATA USED IN A DCF ANALYSIS ARE MOST LIKELY TO CAPTURE INVESTORS' EXPECTATIONS ABOUT THE FUTURE RETURNS?

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[5] Phillips, Charles F., Jr. and Robert G. Brown, *Chapter 9: The Rate of Return,* The Regulation of Public Utilities: Theory and Practice, (1993: Public Utility Reports, Arlington, VA) p. 423.
[6] Ibid, *In re Indiana Michigan Power Company,* 116 PUR4th 1, 17 (Ind. 1990).

A. Yes. As early as 1982, published academic studies showed that analysts' forecasts were superior to historical trended growth rates as predictors of growth rates for DCF analyses.

Q. CAN YOU CITE SOME OF THE STUDIES THAT DEMONSTRATED THAT INVESTORS LOOK TO ANALYSTS' FORECASTS WHEN MAKING INVESTMENT DECISIONS?

A. Yes. A number of authors have addressed the merits of analysts' forecasts in a DCF analysis of the cost of capital. For example, a well-known financial textbook by Brigham and Gapenski states that analysts' growth rate forecasts are the best source for growth measures in a DCF analysis:

> Analysts' growth rate forecasts are usually for five years into the future, and the rates provided represent the average growth rate over the five-year horizon. Studies have shown that analysts' forecasts represent the best source for growth for DCF cost of capital estimates.[7]

Research reported in the academic literature supports this position also. For example, Vander Weide and Carleton found:

> …overwhelming evidence that the consensus analysts' forecast of future growth is superior to historically oriented growth measures in predicting the firm's stock price….Our results are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy-and-sell decisions.[8]

As to the use of the DCF in utility regulatory proceedings, Timme and Eisemann examined the effectiveness of using analysts' forecasts rather than historical growth rates. They concluded:

> The results show that all financial analysts' forecasts contain a significant amount of information used by investors in the determination of share prices not found in

[7] Brigham, Eugene F., Louis C. Gapenski, and Michael C. Ehrhardt, "Chapter 10: The Cost of Capital," Financial Management Theory and Practice, Ninth Edition (1999: Harcourt Asia, Singapore), p. 381.

[8] Vander Weide, James H. and Willard T. Carleton, "Investor Growth Expectations: Analysts vs. History," *The Journal of Portfolio Management*, Spring 1988, pp. 78-82.

> the historical growth rate….The results provide additional evidence that the historical growth rates are poor proxies for investor expectations; hence they should not be used to estimate utilities' cost of capital.[9]

Q. ARE YOU AWARE OF ANY OTHER EMPIRICAL INFORMATION THAT FOCUSES ON THE IMPORTANCE OF COMMON STOCK EARNINGS?

A. Yes. In an "event analysis", a colleague and I compared the market reactions of announced dividends and common stock earnings that were likely to be a surprise to the market. That is, for a group of electric utilities we compared the market reactions to dividend announcements and common stock earnings announcements. Specifically, we looked at the price impact of both earnings announcements and dividend announcements that exceeded *Value Line's* projected levels. Among these companies there were 8 dividend announcements and 19 common stock announcements that exceeded analyst's expectations during the period from September 2001 to December 2003. By developing ratios of a utility's common stock price to the Dow Jones Utility Index, we statistically isolated the impact of these announcements, and linked them to contemporaneous price changes. As Schedule DAM-15 shows, the impact on market prices of the unexpected earnings per share announcement in these cases is dramatic and obvious, and the impact of unexpected dividend announcements is seemingly less so.

Q. WHEN DEVELOPING YOUR DCF ANALYSIS, WHAT DID YOU LEARN ABOUT THE RECENT COMMON STOCK EARNINGS AND DIVIDEND PAYMENTS OF THE COMPANIES THAT YOU STUDIED?

A. I reviewed the dividend and earnings history of the companies studied. As I have illustrated in Schedule DAM-16, the dividends have grown at a lower rate than earnings

[9] Timme, Stephen G. and Peter C. Eisemann, "On the Use of Consensus Forecasts of Growth in the Constant Growth Model: The Case of Electric Utilities," *Financial Management*, Winter 1989, pp. 23-35.

per share in recent years, but this is not surprising in light of the increased competition in the gas distribution industry. Under these increasingly competitive circumstances, prudent boards of directors are likely to conserve cash and refrain from increasing dividends even as earnings grow. Although this relationship may change eventually following the tax reduction on dividends in 2003, the data that I reviewed concerning the comparable LDCs does not yet show this impact.

Q. HOW DID YOU DETERMINE COMMON STOCK PRICES FOR YOUR DCF ANALYSIS?

A. Of course, I was interested in current market valuations; however, recognizing that rates from this proceeding will be in effect for a number of years, I also examined prices over a longer time period. I obtained common stock prices for the past year reported by the *Wall Street Journal.* I also selected current prices from a recent two-week period as reported by *YAHOO! Finance.*

Q. PLEASE EXPLAIN THE FINDINGS FROM YOUR DCF ANALYSIS.

A. Because of the unavailability of DCF estimates for Aquila, Inc., in this analysis I concentrated on the results of the comparable LDCs as cost of common equity benchmarks. In this analysis, for a dividend growth rate I combined historical and forecasted dividend growth rates and used the common stock prices for the past year. This produced low estimates for the comparable companies. I show the results of this DCF calculation in Schedule DAM-17. These results are on the average for the group between 6.23 percent and 7.04 percent. , However, these results are so close to the current level of short-term debt rates and the coupon bond rate of even investment grade utilities that they are not credible measures for the cost of common equity of Aquila in this proceeding. I also used a current common stock share price in a DCF calculation, and it also produced non-credible results for ratemaking. As Schedule DAM-18 shows, these results are 6.40 percent to 6.45 percent on the average which are lower than the current yield on Moody's Baa corporate bonds of 6.59 percent. Schedules DAM-19 and DAM-20 combine the historical and forecasted earnings per share growth rates showing that this DCF produced an extremely high range of estimates. It ranges from a low of 3.64 percent for NICOR to a high of 11.85 percent for the South Jersey Industries when I used the 52-week share prices. After removing NICOR because of its negative growth rate, the model produces an average for the group of 9.75 percent to 10.57 percent. The high-end of the projected earnings per share growth rate DCFs for the comparable LDCs of 10.00 percent and 9.42 percent are probably the most relevant for Aquila Networks - Nebraska in this proceeding. Using the 52-week prices, Southwest Gas is the highest DCF result at 12.26 percent and using recent prices it is 11.49 percent. I have illustrated these results in Schedules DAM-21 and DAM-22.

CAPITAL ASSET PRICING MODEL

Q. YOU STATED THAT YOU USED THE CAPITAL ASSET PRICING MODEL IN YOUR ANALYSIS. WHAT IS THE CAPITAL ASSET PRICING MODEL?

A. The Capital Asset Pricing Model is a risk premium method that measures the cost of capital based on an investor's ability to diversify by combining securities of various risks into an investment portfolio. It measures the risk differential, or premium, between a given portfolio and the market as a whole. The diversification of investments reduces the investor's total risk. However, some risk is non-diversifiable, e.g., market risk, and investors remain exposed to that risk. The theoretical expression of the CAPM model is:

$$K = R_F + ß (R_M - R_F)$$

Where:

K = the required return.

R_F = the risk-free rate.

R_M = the required overall market return; and

ß = beta, a measure of a given security's risk relative to that of the overall market.

In this expression, the value of market risk is the differential between the market rate and the "risk-free" rate. Beta is the measure of the volatility, as a measure of risk, of a given security relative to the risk of the market as a whole. By estimating the risk differential between an individual security and the market as a whole, an analyst can measure the relative cost of that security compared to the market as a whole.

Q. IN YOUR OPINION, WHAT ARE THE ADVANTAGES WHEN USING THE CAPM IN A RATEMAKING PROCEEDING?

A. The CAPM, as a risk premium method, provides a longer-term, more stable perspective of the cost of capital when applied in ratemaking than that of the more volatile DCF analysis. The CAPM takes current debt costs as a basis, or benchmark, for measuring the cost of common stock, which provides this analytical stability. In this way, the CAPM links the incremental cost of capital of an individual company with the risk differential between that company and the market as a whole. Although this is a rather imprecise method, it is a good tool for assessing the general level of the cost of a security.

Q. HOW CAN YOU TELL THAT THE CAPM IS A MORE STABLE MEASURE OF THE COST OF CAPITAL?

A. The CAPM results are likely to be similar for companies in the same industry with similar financial characteristics. In addition, the results are not likely to vary a great deal over time.

Q. WHAT PROBLEMS DO YOU PERCEIVE TO BE IMPORTANT WHEN ONE USES THE CAPM IN A RATEMAKING PROCEEDING?

A. The cost of capital calculations for a company are sensitive to the beta used in the analysis. This beta is a single measure of risk, so, consequently, the CAPM will not incorporate any risks not included in the measures of market volatility. Also, a number of analysts have shown that the CAPM overestimates the cost of capital of companies with betas greater than one and underestimates the cost of capital of companies with betas less than one. In regulation this is important, because most utilities have beta estimates less than one. For example, all of the comparable LDCs except NICOR have *Value Line* betas between 0.70 and 0.85. NICOR has a *Value Line* beta of 1.20. Also, notably Aquila, Inc. has a beta of 1.50.

Q. PLEASE EXPLAIN THE CAPM METHODOLOGY THAT YOU USED IN YOUR ANALYSIS.

A. I applied two different, but complementary, approaches to estimate a CAPM cost of capital. One of these methods examines the historical risk premium of common stock over high grade corporate bonds. The other integrates the risk premium of common stocks to long-term government bonds in recent markets. This method requires an adjustment for the bias because of company size that I mentioned previously. The financial literature has recognized this bias as an empirical problem for a long time, but correcting for this bias is a recent analytical development.

Q. YOU STATED THAT THE FINANCIAL LITERATURE RECOGNIZES THAT THE CAPM METHOD MAY REQUIRE AN ADJUSTMENT FOR A COMPANY'S SIZE. WHAT IS THE NATURE OF THIS RECOGNIZED BIAS?

A. R. W. Banz[10] and M. R. Reinganum[11] in the 1980s, for example, is a good reference pointing out this size bias. Reinganum examined the relationship between the size of the firm and its price-earnings ratio, finding that small firms experienced average returns greater than those of large firms that had equivalent risk as measured by the beta. Of course, the beta is the distinguishing measure of risk in the CAPM. Banz confirmed that beta does not explain all of the returns associated with smaller companies; hence, the CAPM would understate their cost of common equity. In the same time frame, Fama and French confirmed that the Banz analysis consistently rejected the central CAPM hypothesis that beta sufficed to explain investors' expected returns.[12]

Q. WHAT DID YOU MEAN WHEN YOU SAID THAT THE CAPM METHOD REQUIRES AN ADJUSTMENT?

A. Although repeated studies showed that the CAPM method possesses a bias that understates the expected returns of small companies, this remained only an empirical observation without a clear remedy. However, now Ibbotson Associates, which is the common source of data for the risk premium used in CAPM analyses, has developed an adjustment for this bias. Ibbotson Associates discusses the problem as follows:

> One of the most remarkable discoveries of modern finance is that of the relationship between firm size and return. The relationship cuts across the entire size spectrum but is most evident among smaller companies, which have higher returns on average than larger ones. Many studies have looked at the effect of firm size on return. [13]

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[10] Banz, R.W., "The Relationship Between Return and Market Value of Common Stock," *Journal of Financial Economics*, March 1981, pp. 3-18.

[11] Reinganum, M. R., "Misspecification of Capital Asset Pricing: Empirical Anomalies Based on Earnings, Yields, and Market Values," *Journal of Financial Economics*, March 1981, pp. 19-46.

[12] Fama, Eugene F., and Kenneth R. French, "The CAPM is Wanted, Dead or Alive," *The Journal of Finance*, Vol. LI, No. 5, pp. 1947-1958.

[13] Chapter 7: Firm Size and Return, "Ibbotson Associates' Stocks, Bonds, Bills, and Inflation: 2006 Yearbook Valuation Edition," edited by James Harrington and Michael Barad, p. 129.

To account for this empirical bias against smaller companies, Ibbotson Associates has prescribed quantitative adjustments to the CAPM, which it publishes in the same data source used by many analysts to estimate the risk premium in their CAPM analyses.

Q. DID YOU APPLY THE ADJUSTMENT RECOMMENDED BY IBBOTSON ASSOCIATES IN YOUR ANALYSIS?

A. Yes. In my CAPM analysis, I followed the method recommended by Ibbotson Associates to compensate for this inherent data bias.

Q. HAVE ANY REGULATORY COMMISSIONS ACCEPTED THIS SIZE ADJUSTMENT TO THE CAPM IN RATE PROCEEDINGS WHEN DETERMINING THE COST OF COMMON EQUITY?

A. Yes. The Minnesota Public Utilities Commission has done so in an Interstate Power and Light Company case. The Commission observed:

> The Administrative Law Judge takes comfort from the fact that Ibbotson Associates is a widely-recognized statistical reporting firm that has a national reputation. He considers it to be in the same general category as Standard & Poor's or Moody's. There is no indication that the report in question was prepared for IPL, or the utility industry, to bolster arguments in rate cases. Instead, it appears that the report in question is part of an almanac-type yearbook that Ibbotson prepares without any particular focus on the utility industry. The Administrative Law Judge understands and shares the concerns of the Staff concerning the methodology used, and thinks the issue is worthy of pursuit in some other forum. But for purposes of this case, the Administrative Law Judge accepts the principal conclusion of the study – that size of a firm is a factor in determining risk and return.[14]

Q. PLEASE DESCRIBE THE RESULTS OF YOUR CAPM ANALYSIS.

A. My two CAPM studies provide comparative calculations, based on slightly different assumptions. In this way, they serve as benchmark comparisons to the DCF analysis that

[14] *In the Matter of the Petition of Interstate Power and Light Company for Authority to Increase its Electric Rates in Minnesota,* Docket No. E-001/GR-03-767, p. 7.

I had developed previously. Schedules DAM-23 and DAM-243 show the results of my CAPM analyses. Of course, because it is a risk premium analysis, I was able to estimate the cost of common equity of Aquila, Inc. in the current market. The results of the CAPM for Aquila, Inc. were 17.54 percent and 18.66 percent in current markets. However, as I mentioned previously, Aquila, Inc., is now essentially a regulated utility, but the recent restructuring still strongly influences its market-measured capital costs at this time. For this reason the averages of the CAPM results for the comparable LDCs of 12.68 percent and 12.98 percent are more reliable estimates of the cost of capital of Aquila for ratemaking in this proceeding.

Q. HAVE YOU PREPARED A SUMMARY OF THE RESULTS OF YOUR DCF AND CAPM ANALYSES?

A. Yes. Schedule DAM-25 illustrates a summary of the DCF and CAPM results. As I noted previously, the high end of the DCF results are the most reliable, and the averages for the comparable companies are 9.99 percent and 10.57 percent. The CAPM results for the comparable companies are 12.68 percent and 12.98 percent. As I noted previously, I believe that the 17.54 percent and 18.66 percent CAPM results for Aquila, Inc. are higher than necessary for ratemaking in this proceeding.

INTERPRETING THE DCF AND CAPM RESULTS

Q. WHAT DID YOU CONSIDER WHEN YOU INTERPRETED YOUR DCF AND CAPM RESULTS FOR THIS PROCEEDING?

A. I considered the recent and forecasted interest rates, returns on alternative investments, the actual returns to common stock of the comparable LDCs, the identifiable risks of Aquila and the limitations and biases of the DCF and CAPM methods.

Q. HOW ARE INTEREST RATES IMPORTANT TO YOUR INTERPRETATION OF THE DCF AND CAPM RESULTS?

A. Significantly, the levels of interest rates are a measure of the return that investors in utility equities might expect from alternative investments. Consequently, rising interest rates mean that investors will require higher returns from their common stock investments. Relatively speaking, if the risk premium between common stock and debt remains relatively constant, the returns to common stock investments must necessarily increase to attract and maintain capital, and this is an important consideration when establishing an allowed return. Additionally, utilities are capital intensive. Rising inflation and rising interest costs erode the earnings of utilities to a relatively greater extent than industrial companies and therefore are of greater concern to utility investors.

Q. YOU MENTIONED THE ACTUAL RETURNS OF THE COMPARABLE LDCS. WHAT ARE THE CURRENT AND FORECASTED RETURNS OF COMMON STOCK OF THE COMPARABLE LDCS?

A. The average return on common equity of the comparable LDCs in 2006 *Value Line* estimates will range between 9.5 percent for Southwest Gas and 16.0 percent for New Jersey Resources. The average for the group is 11.8 percent. During the 2009-11 period, *Value Line* estimates that the average for the groups' common stock returns will increase to 11.8 percent. I have shown these *Value Line* estimates in Schedule DAM-26.

Q. WHAT OTHER MARKET EVIDENCE DID YOU REVIEW ABOUT RETURNS TO COMMON EQUITY IN ORDER TO PUT YOUR CAPM AND DCF ESTIMATES IN A CURRENT MARKET CONTEXT?

A. I reviewed the recent returns to common stock of some non-regulated industries to view returns to alternative equity investments. I illustrate some of these data in Schedule DAM-27. Although, as expected, the range in recent and expected earnings varies considerably, these data are difficult to interpret. However, one characteristic is relatively similar and important. For the most part, these non-regulated industries are experiencing an increase in common equity returns.

Q. YOU PREVIOUSLY DISCUSSED AN INCREASE IN BUSINESS RISK BECAUSE OF HIGH NATURAL GAS PRICES. HOW DO HIGH GAS PRICES INCREASE THE BUSINESS RISK TO INVESTORS OF AN LDC?

A. High natural gas prices create demand risk for the LDCs and their investors. That is, high prices cause customers to adjust their consumption patterns and LDCs' sales volumes will fall short of levels upon which regulators determined the tariffs. At higher prices, customers reduce their natural gas consumption, install more efficient equipment, and switch to alternative fuels. In addition, high natural gas prices will deter some new customers from even connecting to natural gas utility service. This reduction in gas volumes sold means that LDCs will not earn expected, allowed returns based on larger, anticipated volumes. Investors perceive this threat to projected returns as a business risk. High gas prices also cause receivables to increase. These reduced margins decrease returns to levels less than those anticipated by the allowed returns set by regulators. To investors this increases uncertainty and is a business risk.

<u>RECOMMENDED RETURN</u>

Q. FROM YOUR CAPM ANALYSIS OF AQUILA, INC. AND THE COMPARABLE COMPANIES, YOUR DCF OF THE COMPARABLE COMPANIES, THE

CURRENT COST OF CAPITAL AND ALTERNATIVE RETURNS, HOW DID YOU DETERMINE A RECOMMENDED RETURN FOR AQUILA IN THIS PROCEEDING?

A. As I noted, the CAPM estimates for Aquila, Inc., although it is now principally a regulated utility, are higher than necessary for ratemaking because of the market-effects of the capital restructuring. The CAPM results for the comparable LDCs by two different, confirming methods are very similar. These are 12.68 percent and 12.98 percent.

The DCF results for the comparable companies are very sensitive to assumptions about the current market, and they do not represent the relative risks of Aquila. Probably the actual returns of the comparable LDC group are very significant for ratemaking in this instance. This is a measure of the returns for similar investments in utilities in similar businesses. This group should earn an average return on common stock in 2006 of 11.8 percent according to *Value Line*. In light of rising interest rates, I recommend that the allowed return for Aquila Networks - Nebraska be set in the range of 11.75 percent to 12.25 percent. Because of the uncertainties of the cost of raising capital to support utility service going forward, I believe that from the mid-point of this range, or 12.0 percent, to the upper end of the range, or 12.25 percent, is necessary for Aquila to attract capital in the current market. Looking at my recommendation from the perspective of investing in comparable LDCs, Aquila must at least be able to provide the same returns to existing and prospective common equity holders as its peer LDCs. That is precisely what the group of comparable companies represents, and my recommendation is in line with their current and forecasted earnings on common stock.

Q. WHAT IS THE TOTAL COST OR CAPITAL THAT YOUR RECOMMENDED ALLOWED RETURN ON COMMON EQUITY REPRESENTS?

A. At the 12.0 percent on common stock for Aquila Networks - Nebraska, which I recommend as a minimal return, will produce a total cost of capital of 9.60 percent. The upper end of my range, or 12.25, percent will result in a total cost of capital of 9.73 percent. I have illustrated this total cost of capital in Schedule DAM-28.

FINANCIAL INTEGRITY TEST

Q. YOU STATED PREVIOUSLY THAT YOU TESTED THE ADEQUACY AND APPROPRIATENESS OF YOUR RETURN RECOMMENDATION. HOW DID YOU TEST YOUR RECOMMENDED ALLOWED RETURN FOR AQUILA FOR ITS ADEQUACY AND APPROPRIATENESS?

A. As a direct measure of the financial integrity of my recommended allowed return range, I compared the After-Tax Interest Coverage ratios of Aquila at the high end and middle of this range to the coverages of the comparable LDCs. The After-Tax Interest Coverage is a measure that implies the likelihood that Aquila will have sufficient funds available to meet its fixed interest obligations should it earn at my recommended allowed return. The higher the coverage ratio the greater the likelihood that the allowed return will provide funds to meet the fixed interest obligations. Of course, because of the various business risks that can occur, the Company has no guarantee that it will earn this return. If it does earn at this level, this measure will show how its interest coverage will compare to the comparable LDCs. For my analysis, I simply determined if my recommended allowed return would result in interest coverage similar to the comparable LDCs.

Q. ASSUMING AQUILA ACHIEVES YOUR RECOMMENDED ALLOWED RETURN, HOW WOULD THE AFTER-TAX INTEREST COVERAGE RATIO FOR AQUILA COMPARE TO THE COVERAGES OF THE COMPARABLE LDCS?

A. The After-Tax Interest Coverage ratio of Aquila that would result from the minimal recommended allowed return on common equity of 12.0 percent is just 2.73 times. By comparison, the average After-Tax Interest Coverage of the comparable companies is a much higher and less risky coverage of fixed interest obligations of 3.62 times. Only Southwest Gas would have interest coverage lower than Aquila at my recommended return level. By any measure, the coverage of my minimally recommended allowed return is extremely low.

Q. DID YOU DETERMINE THAT THE UPPER END OF YOUR RECOMMENDED ALLOWED RETURN WOULD PROVIDE AN AFTER-TAX INTEREST COVERAGE THAT IS CLOSER TO THE COVERAGE LEVELS OF THE COMPARABLE LDCS?

A. If Aquila earns at the upper end of my recommended allowed return, this will do effectively reduce the measured coverage risk of Aquila *vis-a-vis* the comparable LDCs. Even at the upper-end of my recommended range, the After-Tax Interest Coverage is still only 2.77 times. Consequently, a return at the upper end of my recommended allowed return range will not move Aquila above the low end of the coverages of the comparable LDCs. This test confirms that my recommendation is very conservative, especially in the light of the uncertainty that Aquila can or will actually achieve this allowed return.

Q. HAVE YOU PREPARED A SUMMARY OF THESE COMPARATIVE INTEREST COVERAGE RATIOS AT THIS ALTERNATIVE RETURN LEVEL?

A. Yes. I have prepared a comparison of these interest coverage rations which I have illustrated in Schedule DAM-29.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

BEFORE THE NEBRASKA PUBLIC SERVICE COMMISSION

In the matter of Aquila, Inc.	)	
d/b/a Aquila Networks ("Aquila")	)	Docket No. NG-xxxx
seeking a general rate increase	)	Docket No. NG-xxxx
for Aquila's Rate Areas One, Two	)	Docket No. NG-xxxx
and Three (not consolidated)	)	

Direct Testimony of Stephen L. Pella

Vice President, Nebraska Operations

Policy

November, 2006

Stephen L. Pella
1600 Windhoek Drive
Lincoln, NE 68512
402-437-1725

Introduction

Q. Please state your name and business address.

A. My name is Stephen L. Pella, and my business address is 1600 Windhoek Dr., Lincoln, Nebraska 68512.

Q. By whom are you employed and in what capacity?

A. I am employed by Aquila, Inc. ("Aquila" or "Company") in the position of Vice President of Operations for Nebraska.

Q. Please describe your qualifications and experience?

A. I have nearly 30 years in the energy industry, with diverse business experience. I have managed multiple business functions with positions in both the natural gas and electric segments of the industry. In recent years, I have held senior management positions with Aquila, including Vice President, Power Supply; Vice President, Corporate Strategic Planning; Vice President, Distribution; and Vice President, Energy Delivery. Earlier, I held positions with responsibility over various functions for the company including administration, marketing, and technical services.

Q. Would you please describe your responsibilities as Nebraska's VP of Operations.

A. I am responsible for the financial and operational performance of Aquila's operations in the state of Nebraska. I oversee all state operating functions including gas distribution network operations, maintenance, construction, customer service, customer relations, community relations and economic development. I am also indirectly involved in the oversight of certain other functions that are centralized within Aquila and provide support to Nebraska Operations, which include gas supply, regulatory affairs, legislative affairs and central services such as call center functions.

Q. Please describe the Nebraska Gas Operations.

A. Aquila serves over 192,000 customers in roughly 110 towns & areas in the eastern third of the state. Operations Centers are located in the various central & key locations served by Aquila and include Lincoln, Papillion, Beatrice, York, Columbus, and Norfolk.

Q. Have you previously testified before any regulatory agencies?

A. Yes. I have testified before the regulatory agencies in Missouri, Kansas, and Arkansas.

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony in this proceeding is to explain in general terms,

1) why Aquila is seeking rate relief at this time and what cost recovery mechanisms are being proposed,

2) the steps we have taken to insulate customers from the costs associated with our company's financial repositioning, and as reflected in our utility performance and our commitment to utility operations,

3) our efforts to manage our costs, and

4) to introduce the other Company witnesses.

Reasons for Rate Increase

Q. What is the level of increase being requested?

A. We are filing a request for an annual increase in rates in Nebraska of approximately $16.3 Million.

Q. Please explain the reasons for Aquila's request for rate relief.

A. There is no good time to request an increase in rates. However, it has been nearly four years since our last rate case, which used a 2002 test year. Since that time, we have invested heavily in our natural gas distribution system in the state and our expenses to run the business have risen. Aquila's existing rates are inadequate to reflect that increased level of investment and to recover operating and maintenance costs. Existing rates fail to provide an opportunity for a fair and reasonable return on the investment in Aquila's Nebraska gas distribution business. As a consequence, we are requesting rate relief as permitted under the State Natural Gas Regulation Act.

Q. What are the main drivers for the need to increase rates?

A. Generally, the main drivers of the proposed rate increase for Nebraska are:

(1) necessary capital investments to continue providing safe and reliable service,

(2) increased operating costs, including labor, materials, fuel, insurance and depreciation, and increases in the costs for Central Services to support our state utility business, and

(3) more efficient use of energy by our customers.

Q. What specific events are driving the need for this request?

A. There are three key drivers:

1) Investment in plant, equipment, and gas-in-storage, has increased significantly since the time of the last rate case filing. We have invested over $42 million in plant since the last rate case.

2) Overall operating expenses (O&M, Depreciation and Taxes-Other-Than-Income Taxes) have increased over 35% since the last rate case. Normal inflation on costs would account for more than 10%. Many expenses like medical and other benefits, fuel and insurance costs have increased at even higher rates. Depreciation has also increased from our significant investments, and from realigning our depreciation rates to better reflect the expected useful lives of our investments to serve our customers. In addition, support services to customers provided by central-based functions, such as Accounting, Billing, Human Resources and Call Centers, have also increased.

Besides normal inflationary increases, these support services costs, in a small measure, have increased due to the effect of serving a smaller domestic customer base.

3) Natural gas conservation continues to erode utility revenue as more efficient homes and appliances are added and customer conservation increases. Because most operating costs do not vary directly with sales of gas, conservation tends to reduce margins more than proportional costs can be reduced.

Q. Are there any other elements of this rate case proceeding?

A. Yes. We are introducing new mechanisms to economize the regulation and enhance the operation of our natural gas utility business.

1) Aquila is proposing a Limited Cost Recovery mechanism to reflect a portion of the annual increases in the costs of operations and of the costs to pursue fair rates. This mechanism will allow smaller but more frequent rate increases. This mechanism is comparable to an earlier filing made by Aquila in 2005 for a "limited cost recovery" to address these annual cost increases. That request was not approved by the Commission because it was filed outside of a formal rate proceeding.

2) Consistent with Aquila's endorsement of the National Action Plan for Energy Efficiency, unveiled by the National Association of Regulatory Utility Commissioners ("NARUC") earlier this year, two energy efficiency programs are also being proposed:

i) the first program will provide assistance to customers that qualify as low income to weatherize their homes and replace low efficiency appliances, and

ii) the second program offers rebates to other customers to help them purchase high efficiency furnaces and water heaters.

These proposed programs are extensions of our existing efforts to aid consumers in making the most effective, efficient and affordable use of natural gas. Our existing programs include donations through “Aquila Cares” partnership in the Nebraska Energy Assistance Network, and organizing volunteers for weatherization projects. Lowering the demand for natural gas will lower the price and cost for the benefit of all customers, and continue to keep energy affordable.

3) Aquila is proposing two decoupling mechanisms in combination with the traditional two-part rate design. These decoupling mechanisms address the volatility of gas bills from weather as well as the negative earnings impact of conservation. The proposed decoupling mechanisms are as follows:

i) A Weather Normalization Adjustment (“WNA”) mechanism is proposed to remove the impacts of non-normal weather, and

ii) a Revenue Normalization Adjustment (“RNA”), which combines the WNA with a conservation tracker.

Consumer Protection

Q. Please explain Aquila's repositioning efforts in completing its transition to an investment-grade Midwestern utility?

A. Aquila's repositioning has been a rather complex, multi-year effort and is nearing its completion. The goal of this repositioning was to reduce debt to a level more in line with utility expectations. To this end, Aquila has sold all of its international utility properties, has essentially wound-down its energy merchant business, and is selling some of its domestic utility properties. Aquila's debt level, which once was over $2.4 Billion, is now moving closer to $1 Billion. Credit metrics have improved for Aquila as evidenced by Fitch Ratings, Moody's Investor Services and Standard & Poor's recent upgrade of Aquila's debt rating. Our hope is to be at a credit rating BB in the near future, and then move to the BBB investment grade level thereafter.

Q. What commitments has Aquila made to insulate its regulatory customers during the Company's financial repositioning to all state regulatory bodies with jurisdiction over its utility operations,?

A. Aquila has focused, and will maintain that focus, on three key business principles:

1) protect customers from potential adverse financial impacts of events not directly associated with utility operations,

2) maintain quality customer service, and

3) enhance regulatory transparency by continuing open, ongoing dialog with regulators to assure them that Aquila's books and records fairly and accurately represent the cost of utility operations for rate making purposes.

Q. Please explain further how customer rates are protected from any adverse financial impact of events that are not directly related to utility operations.

A. Aquila's capital allocation process is one way that customer rates are protected. Aquila utilizes "hypothetical" capital structures and long-term debt assignments that are comparable to other gas distribution companies for ratemaking purposes.

Q. Please describe the capital allocation process.

A. Aquila has maintained a capital assignment process since 1988 that was specifically designed to insulate and separate each of its utility divisions from the other activities of the Company. Aquila has not changed this practice. Aquila's regulated utility operating units are assigned and receive capital based upon what a comparable utility would receive, and this process has been presented to Commissions in states we serve since the 1980's.

Q. What cost of debt is used in the capital assignment process?

A. While I leave the details for the cost-of-capital to Aquila's expert witness, Dr. Donald A. Murry, Aquila uses the lower of the actual cost of the debt issue or an interest rate that is no higher than investment-grade bonds at the time the debt is dedicated to utility needs. In other words, the rate payers will not pay more than an investment grade utility for the cost of its debt even if the actual cost of debt to Aquila is greater. This approach shields Aquila's regulated customers from the consequence and impact of higher risk Aquila activities and resulting interest charges. Therefore, in short, Aquila's customers only pay the investment grade equivalent for debt instead of the actual higher cost of debt held by Aquila.

Q. Are there any other costs that have been eliminated from this case to protect the customer rates?

A. Aquila has eliminated the costs related to executive bonuses and incentives; repositioning costs such as consultants, advisors, and any other transaction fees unrelated to Nebraska operations; the bonus components for calculating the Company's supplemental executive retirement plan; and any prepayments caused by Aquila not being investment grade. The revenue increase being requested is to recover only those costs necessary for Aquila to continue to provide safe and reliable natural gas utility service to its Nebraska customers.

Q. Have the negative financial conditions or repositioning efforts unfairly impacted the cost of service paid by your utility customers?

A. No. Utility customer rates have not been unfairly impacted as a result of our financial repositioning efforts. Aquila's Nebraska gas utility customers are paying for only those central functions and corporate services that are being used to provide service to Nebraska customers; those costs have been reduced to a level commensurate with the size of our utility after completing the sales of some of our utility properties. As discussed further in Dr. Murry's testimony that level of costs compares favorably to similarly sized utilities. Moreover, all employees associated with the preparation of this rate request have been instructed to ensure that no impacts of the financial challenges from Aquila's non-regulated businesses be included in the determination of regulated revenue requirements.

Q. Would you now please discuss the second key business principle and the commitments Aquila has made to service quality?

A. Yes. Maintaining quality customer service requires attention in three main areas: 1) Continue appropriate funding of capital expenditures, 2) Ensure adequate staffing, and 3) Set and monitor customer service performance metrics.

Q. Has your commitment to invest in your utility infrastructure remained?

A. Yes. In fact, our investment in the Nebraska distribution system has more than doubled over the past three years. Our total annual capital investment is now roughly $15 million.

Q. Please explain how appropriate capital spending impacts customer service.

A. The State Natural Gas Regulation Act and the Pipeline Safety Act require Aquila to maintain a safe and reliable natural gas system. In addition, Nebraska communities in which we serve demand that Aquila maintain and grow its distribution system where it is economically feasible to do so. In response to these business demands or as required by these laws, Aquila invests significantly in extending and improving its natural gas distribution system. Aquila looks at numerous requests to extend its system, and continually monitors its system and software to make the appropriate capital investments consistent with our business and state and federal mandates.

Q. Please explain how adequate staffing impacts customer service.

A . Aquila's focus on its customers and service obligations in Nebraska demands that it has qualified employees in sufficient numbers to provide the customer service and support needed in Nebraska. All of the employees needed to operate and maintain the distribution system, whether located in Nebraska or elsewhere, are committed to assuring that a high quality of customer service is provided to Aquila's Nebraska customers.

Q. Has this repositioning effort distracted state employees from providing quality service to Aquila customers in Nebraska?

A. Absolutely not. I meet continually with all levels of employees as the state leader in Nebraska. I continue to take personal and professional pride in the dedication of our employees in serving our customers. This dedication has held fast through all the company repositioning effort and that dedication is strengthened as we approach its successful conclusion. Our employees continue their commitment to supporting our communities, and their performance and impact is acknowledged locally.

Q. Are there other ways the utility provides service to Nebraska customers?

A. Yes. As a community partner, Aquila remains active in numerous civic and community activities through economic development initiatives, financial contributions and the involvement of our dedicated employees. Aquila has been involved in a broad range of projects to improve our local communities, including education of youth through Junior Achievement programs, Habitat for Humanity projects, other housing improvements through the Nebraska Community Improvement Program (NCIP), involvement in local United Way campaigns, and various other community initiatives. We see ourselves as "partners" in our communities; while we see all of our investment here as justifiable, we are only seeking 50% of our charitable contributions in this case. Our value is being recognized, as a utility and community partner, as we continue to renew utility franchises across our service territory. Since 2005, we have renewed nearly 30 franchises. In addition, Aquila has programs to raise funds which, along with company matching, provide resources to those customers in need with their energy bill.

Q. How does Aquila implement its commitment to delivering quality services to its customers?

A, Aquila has developed internal service quality metrics (performance metrics) whose goals are set relative to industry standards, federal and state regulation, and state-specific considerations including geography and history. These performance metrics include timeliness of meter reading [target 98%], accuracy of meter reading [target over 99% accuracy], effective collection of accounts receivable [over 98%], safety measures including the frequency of employee injuries necessitating time lost away from work and vehicle accidents [targets above industry averages], rapid response to emergency calls [beyond DOT requirement of 97% within 60 minutes], and the number of firm service interruptions [ideally zero].

These metrics are a primary management tool to ensure that our customers are being well-served. These metrics are routinely and regularly reported to me - I subsequently discuss service quality performance with my management team and review it with utility personnel across the state. In turn, I provide monthly status reports to Aquila's senior management on these metrics. The metrics are also published internally on the Aquila intranet for all employees to review.

Detailed reviews of service quality performance for the state are conducted with the company's top executives on a quarterly basis. Because of their importance, these metrics are included in the goals for all Aquila employees, and are the cornerstone of the Company's variable compensation plan, as explained in detail by Company witness, Jerl Banning. A strong commitment also exists for employee training and development to assure consistently solid utility performance.

Q. Turning to the third key business principle, what do you mean by enhancing regulatory transparency?

A. In the mid-1990s, Aquila made the decision to centralize its utility operations in order to gain economies from transitioning to common accounting and billing systems, standardized operational practices, and common executive management. Having achieved these economies, Aquila now operates in a state-based utility organization that is benefiting from the common platforms and is focused on providing solid service to its customers. Formal procedures exist for the proper allocation of costs from central service providers to state operations. Aquila continues to enhance the transparency of its utility structure, which should ultimately further facilitate the understanding and review of our operations.

While I leave the accounting and other details of Aquila to other witnesses, Aquila attempts to work with its regulators and the Public Advocate in each of its regulatory or tariff filings, follows the Uniform System of Accounts, and make reasonable efforts to keep its regulators informed of significant events affecting Aquila in Nebraska or other jurisdictions.

Managing Costs

Q. What has Aquila done to contain costs and improve operating efficiencies in providing utility service?

A. Aquila has implemented a number of initiatives to contain costs and improve operating efficiencies. A process improvement methodology, called Six Sigma, has been introduced in the Company and has been operational for three years. Using this methodology, teams of employees have addressed well over 50 projects and to-date have delivered several million dollars of savings, provided other non-financial efficiencies, and/or more effective service practices. In addition, various other teams form to address operating and service issues not requiring the discipline of Six Sigma. Finally, the Company continues to leverage central purchasing and contracting for goods and services. This leverage allows for volumetric purchases including pipe and related materials from suppliers at competitive prices. This leverage also enhances the competitive bid processes for the services of third party construction and maintenance contractor crews.

Q. What is the status of reductions in central support function costs?

A. Central support functions include such utility services as Billing and Call Centers, and corporate services like Information Technology and Accounting. With the sale of some utility properties, the level of central support is being re-sized to a level appropriate for Aquila's remaining customer base. The Company has actively worked to eliminate the majority of those costs that were previously allocated to the sold states. This plan is intended to achieve targeted cost savings in early 2007.

Q. What level of central support cost reductions is anticipated?

A. The cost of central support services previously allocated to the states that have been identified for sale was $42.3 million. Of this amount, Aquila has targeted a reduction of $37.5 million. The difference between these two amounts recognizes that certain costs are fixed and, therefore, do not decrease ratably with reductions in customers, plant-in-service, and employees. Examples of these kinds of cost are SEC reporting requirements, Sarbanes Oxley compliance, Billing and Accounting systems, and Corporate Treasury functions.

Witnesses

Q. What witnesses will be used to sponsor the exhibits filed in this case?

A. Seven Company witnesses are sponsoring the exhibits that accompany the application. They are as follows:

1) Richard G. Petersen, Director of Regulatory Accounting, is responsible for all Base Year numbers and is also sponsoring several accounting adjustments for known and measurable changes that have taken place since or during the test period;

2) Vern J. Siemek, Senior Financial Manager for Nebraska is sponsoring several pro-forma adjustments and the Limited Cost Recovery proposal;

3) Glenn W. Dee, State Regulatory Manager for Nebraska is sponsoring the lead lag study and calculation of Cash Working Capital, along with other pro forma adjustments;

4) Ruth Gustin, Aquila's Benefits Manager, is sponsoring the increase in health benefits;

5) Phil Beyer, Aquila's Director of Benefits and HR Information Systems is sponsoring the pro forma adjustment in pension expense;.

6) Jerl Banning, Aquila's Compensation Director is supporting Aquila's two-part compensation plan; and

7) Matt Daunis, Aquila's Manager of DSM/Energy Efficiency is sponsoring the low-income weatherization program and other energy efficiency programs.

Q. Has the Company employed any outside consultants to assist them in the preparation of this requested rate increase?

A. Yes, Aquila has hired several outside consultants to assist the Company with very specific issues. Those witnesses are:

1) Donald A. Murry, Ph.D. and Vice President of C.H. Guernsey & Company from Oklahoma City, who has analyzed Aquila's cost of capital and has recommended an appropriate return-on-equity for retail natural gas distribution service in Nebraska;

2) Thomas Sullivan, Project Manager for Black & Veatch Corporation from Kansas City has developed a fully allocated class cost of service study for all three Nebraska rate areas, and sponsors the traditional rate design; and

3) Paul H. Raab, independent economic consultant from Washington, D.C. has used regression analysis on 30-year weather data to determine sales and purchase volumes expected during normal weather. In addition, Mr. Raab has taken the regression coefficients developed from the weather data and determined what non-gas revenue can be expected during normal weather and is sponsoring the WNA mechanism. Mr. Raab also sponsors the RNA, which combines the weather and conservation tracker as an alternate to the WNA.

Q. Please summarize Aquila's request in this application.

A. The witnesses have supported several alternatives, but Aquila's base case can be summarized by the following:

1. Increase annual revenues by $16.3 MM,

2. Collect the annual revenue requirements using a traditional two-part rate design together with the RNA tracker to fairly counter the impacts of weather and conservation,

3. Implement the LCR mechanism to allow smaller but more frequent future rate increases, and

4. Implement energy efficiency programs to promote conservation efforts, which will lower demand and gas prices for all customers in the future.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE NEBRASKA PUBLIC SERVICE COMMISSION

In the matter of Aquila, Inc.)	
d/b/a Aquila Networks ("Aquila"))	Docket No. NG-xxxx
seeking a general rate increase)	Docket No. NG-xxxx
for Aquila's Rate Areas One, Two)	Docket No. NG-xxxx
and Three)	

Direct Testimony of Richard Petersen

Director of Gas Regulatory Accounting

Base Year Accounting

November 15, 2006

Richard G. Petersen

1815 Capitol Ave.

Omaha, NE 68102

402-221-2047

<u>Introduction</u>

Q. Please state your name and business address.

A. My name is Richard G. Petersen and my business address is 1815 Capitol Avenue, Omaha, Nebraska.

Q. By whom are you employed and in what capacity?

A. I am employed by Aquila, Inc. (Aquila) in the Regulatory Services Group. My position is Director of Regulatory Accounting-Gas.

Q. Please state your educational background and experience.

A. I attended Dana College in Blair, Nebraska, from which I received a Bachelor of Science Degree in Business Administration. I began working for Northern Natural Gas Company and held various positions in the accounting and regulatory departments. In 1985, UtiliCorp United, Inc. (now known as Aquila) purchased the Peoples Natural Gas Division from Northern Natural Gas Company (known as InterNorth, Inc. at that time). I have held various positions in the accounting areas within Peoples and UtiliCorp United, Inc. I assumed my current position in June 1998.

Q. Have you previously filed testimony before any regulatory bodies?

A. Yes. I have filed testimony before the Iowa Utilities Board, the West Virginia Public Service Commission, the Michigan Public Service Commission, the

Missouri Public Service Commission, the Nebraska Public Service Commission and the State Corporation Commission of Kansas.

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to present certain schedules in support of the proposed rate increase by Aquila as required by the Minimum Filing Requirements of the Commission (Rule and Regulation Nos. 157 and 157A, Title 291, Chapter 9).

Q. Please identify the schedules you are sponsoring.

A. I will be sponsoring Base Year accounting data, which is unadjusted from the Company's books and records, and certain accounting adjustments related to payroll, incentives, pensions, medical costs, retiree medical costs, corporate cost allocations and changes in allocations resulting from the sale of four Aquila state utility properties, depreciation, payroll taxes, property taxes and postage expense.

Q. Were the schedules and adjustments you are sponsoring prepared by you or under your supervision?

A. Yes.

Q. Are the facts and amounts contained in these schedules and adjustments correct, to the best of your knowledge, information and belief?

A. Yes.

Q. How does Aquila maintain its books and records?

A. Aquila maintains its books and records in accordance with the Federal Energy Regulatory Commission Uniform System of Accounts, as adopted by the commission.

BASE YEAR

Q. What is the Base Year for this rate case filing?

A. The Base Year is the twelve month period ended June 30, 2006.

TEST YEAR

Q. What is the Test Year for this rate case filing?

A. Aquila used the historical Base Year for the twelve months ended June 30, 2006, adjusted for known and measurable changes.

Q. Please explain the financial schedules you are supporting.

A. Exhibit I, Schedule A, columns 1 and 2 calculates the Base Year and Test Year revenue deficiencies. Exhibit I, Schedule B assigns the Test Year deficiency to customer classes per the Cost of Service Study performed by

Aquila's consultant. Exhibit II, Schedules A, B and C, provides Base Year data by Rate Area for capitalization (Schedule A), rate base by FERC account (Schedule B), and operating revenues and expenses by FERC account (Schedule C). Schedule D provides the Base Year Income Tax Calculation by Rate Area.

ADJUSTMENTS

Q. Please explain who will support the accounting adjustments to the test year income statement data.

A. The adjustments will be supported by a number of Company witnesses. Mr. Vern Siemek will support capital additions, the Offutt Air Force Base housing adjustment, the loss of the OPPD electric meter reading contract, gas storage valuation and an adjustment to insurance costs. Mr. Glenn Dee will support the addition of the Lincoln Lateral Line investment, a bad debt margin adjustment and the amortization of deferred rate case costs. Mr. Phil Beyer will present actuarial studies to support the pension cost adjustment, and Ms. Ruth Gustin will provide support for rising health care costs reflected.

Q. Will you support the remaining adjustments?

A. Yes. I will support the remaining adjustments including, depreciation annualization; annualization of payroll costs including the dollar impact of the change in allocation bases related to the sale of Aquila gas utility properties in Michigan, Minnesota, Missouri, and Kansas electric properties; reductions in costs related to operating efficiencies and staff eliminations; merit salary increases for non-union employees; contractual salary increases for union employees; adjustments to advertising, dues and contributions; employee benefit cost increases; annualization of property taxes; and a postage adjustment. Mr. Paul Raab, an outside expert witness, will provide the weather normalization adjustment.

Q. Please explain the adjustments in Section 9, Schedule 2.

A. Adjustment No. 1 reflects the impact of capital additions, and will be supported by Mr. Vern Siemek.

Adjustment No. 2 reflects changes in investment and service to the Offutt Air Force Base housing area, and will be supported by Mr. Vern Siemek.

Adjustment No. 3 reassigns the investment for the Lincoln Lateral Line and will be supported by Mr. Glenn Dee.

Adjustment No. 4 reflects adjustments to depreciation expense and reserves. Depreciation expense was adjusted to reflect the annualization of expenses based on June 30, 2006 plant balances. The adjustment is the difference between the actual expense for the twelve months ended June 30, 2006 and the annualized year-end amount, and recognizes changes in the annual level of expense associated with additions and retirements occurring during the test year. The adjustment also includes updated depreciation rates resulting from a study performed by outside consultants Foster and Associates, and an adjustment for common assets that serve all utilities in the Aquila Network.

Adjustment No. 5 adjusts Aquila's investment in Gas Storage, and will be supported by Mr. Glenn Dee.

Adjustment No. 6 was made to annualize payroll expense to reflect changes in payroll costs through August 15, 2006. Nebraska direct and allocable payroll expense was annualized by using base payroll by department at August 15, 2006, since this reflected the most current pay levels in effect at the time the adjustment was prepared. The annualized base pay amount was also adjusted for known vacancies and other than base payroll categories such as standby, overtime and callout pay.

Q. How was the vacancy portion of the adjustment determined?

A. A list of current direct open positions that are in the process of being filled for Nebraska operations was obtained from the Aquila Human Resources Department. Any open part-time or temporary positions were eliminated from the vacancy adjustment. The dollar value of the open positions applicable to Nebraska was determined based on using the minimum of the salary range for the open positions. The cost of the open positions was added to the annualized payroll amount.

Q. What was the process for vacancies in departmental positions that allocate costs to Nebraska operations?

A. The same process was followed in determining the cost of vacancies for those positions that will allocate costs to Nebraska. Once the value of these positions was determined, the costs were assigned to Nebraska based on the allocation percentages applicable for that particular department.

Q. What was the next step?

A. The annualized payroll expense was compared to the year ended June 30, 2006 actual payroll to determine the amount of the adjustment. The adjustment was then allocated between utility and nonutility operations, and payroll amounts capitalized based on actual experience for the twelve months ended June 30, 2006. The amount applicable to utility expense was then allocated to FERC accounts based on the 12 months ended June 30, 2006 actual expense by FERC account.

Q. Were other adjustments made related to this payroll adjustment?

A. Yes. Employee benefits and taxes other than income taxes were adjusted to reflect the impact on benefits and associated payroll taxes based on changes made to payroll expense.

Q. Please continue with your adjustment explanations.

A. Adjustment No. 6 also reflects an update to the employee variable compensation accrual**.** Aquila maintains a variable compensation or incentive pay plan for non-union employees, which is based on both the achievement of individual objectives and non-financial company objectives. This is combined with fixed or base salaries to equal an employee's total compensation. The adjustment was split between utility expense, non-utility expense and payroll capitalized, and the utility expense was allocated to FERC account based on actual payroll expense by FERC account for the twelve months ended June 30, 2006.

Q. Please describe “non-financial” company objectives.

A. Non-financial company objectives include satisfactory customer service, service reliability, effective use of capital for projects, safety and to maintain or reduce Aquila’s cost of service. Employees have objectives that are related to improvements in these five non-financial areas, and also have objectives for individual projects related to their work responsibilities.

Q. Please continue.

A. Variable compensation amounts are accrued monthly in 2006 to reflect expected payments in March 2007 for completion of employee objectives for variable compensation. The amount accrued through June 2006 was adjusted to reflect an entire year’s accrual for payment at roughly the midpoint of the variable compensation payout.

Q. Is there an additional component of the variable compensation adjustment?

A. Yes. <u>Adjustment No. 7</u> reflects a revision made to the 2006 employee variable compensation plan to increase opportunities for employees for achievement of non-financial incentive goals and work projects. The accrual was adjusted to reflect the latest variable compensation plan.

Q. Please continue with Adjustment No. 8.

A. Adjustment No. 8 reflects the amortization of anticipated rate case expenses over a three year period. Mr. Glenn Dee will support this adjustment.

Adjustment No. 9 is referred to as an EOS ("Economies of Scale") adjustment and reflects changes in staffing levels that have, and will continue to occur at Aquila, particularly in the support functions of Aquila. Adjustment No. 6 for the payroll annualization reflected the cost allocation percentages in effect after the 2006 sale of Michigan, Minnesota and Missouri gas properties, and the upcoming sale of Kansas electric properties. These property sales resulted in the elimination of direct employees and related costs in those states being sold, as well as a number of corporate staff positions being eliminated. However, certain corporate staff positions could not be eliminated due to continuing work requirements; any such corporate staffing positions would continue to be assigned to the remaining states. The payroll annualization adjustment therefore represents end-of-period staffing, salary and current allocation percentages. The post-sale net reductions in corporate staffing as allocated to Nebraska are referred to as "EOS " savings. Please note that any severance payments made to corporate employees that are terminated as the result of the property sales will not be charged to Nebraska.

Q. You mentioned that current allocation processes were used. Please explain the allocation process.

A. Corporate and support costs that are not charged directly to Nebraska gas operations, are allocated to Nebraska from departments classified under two activities. The prior "Enterprise Support Functions" (ESF) have recently been renamed Aquila Corporate, or "AQLCP", and are costs incurred at the Corporate level involving general support for all of Aquila. An example of this would be the Treasury Department. The prior "Intra-Business Units" (IBU) have also been renamed and are now referred to as Network Company or "NETCO" costs, and represent costs incurred by departments that support utility operations, but do not charge directly to state gas and electric operations. An example of this would be the Call Center for customer service. The first priority in the cost assignment process is to charge costs directly to Nebraska operations if at all possible. If this is not possible, then the costs are allocated on a specific cost driver. An example of this would be to assign corporate human resource costs on the number of employees by state. Finally, if costs are not charge directly, or allocated on a specific cost driver, the costs are allocated to states based on a general allocator. An example of a general allocator is an average of payroll, gross margin and net plant percentages by state that would be used to allocate the costs of the Corporate Treasury Department.

Q. Does Aquila have a summary of the allocation procedures and percentages?

A. Yes. The process is detailed in Aquila's Cost Allocation Manual which is updated periodically and is available for review.

Q. Were there significant changes in the allocation process in the test year?

A. While there were not any changes in the process itself, the sale by Aquila of the gas properties in Michigan, Minnesota and Missouri, and the pending sale of the Kansas electric properties, caused some change in the assignment of costs by state, as mentioned previously on Page 9, Line 17 of my testimony. The cost allocation drivers were changed for corporate reporting purposes effective January 1, 2006 to reflect the sale and elimination of these state operations.

Q. Why were the allocation percentages changed effective January 1, 2006?

A. For SEC reporting purposes, the utility properties to be sold in 2006 were classified as discontinued operations, per Statement of Financial Accounting Standard No. 144 (SFAS 144), and only the direct operating costs were assigned to these discontinued operations. Therefore, "AQLCP" and "NETCO" allocable costs are reported in 2006 as part of Aquila's retained and continuing utility operations.

Q. How were AQLCP and NETCO costs assigned to Nebraska gas operations for the test period ended June 30, 2006?

A. All adjustments in this filing have been allocated to Nebraska based on the allocation percentages in effect at January 1, 2006.

Q. Does this change unfairly burden the state utility properties remaining as part of Aquila's continuing operations?

A. No. While it is true that allocable AQLCP and NETCO department costs would be theoretically assigned to the remaining states thereby increasing their costs, these increases are significantly offset by reductions in all allocable department costs. These reductions have occurred and will continue to occur throughout all of 2006 to reflect the reduced operational requirements of a smaller Aquila. When the sale of the four state utility properties was announced, Aquila embarked on a cost reduction program to recognize that Aquila would be a smaller company, with less need for certain support costs. Direct costs in the remaining Aquila states were minimally affected.

For Corporate allocable costs, Aquila made a commitment to specific levels of reduced support expenses, both payroll and non-payroll, for all departments.

Q. Could you provide an example of this?

A. Yes. At the end of the test period on June 30, 2006, a large number of staff reductions have already been made, and are reflected in Aquila's payroll annualization adjustment. For the balance of the year certain positions and costs remain to be eliminated. The impact of these known reductions/savings have been identified, totaled and appear as "EOS " Adjustment No. 9.

Q. Please expand on the nature of the "EOS savings" adjustment.

A. This adjustment represents the value of additional reductions in the number of employees known at this time and scheduled for elimination between the end of the Test Year of June 30, 2006 and December 31, 2006.

Q. Were any other allocable payroll costs eliminated from the test period?

A. Yes. Any 2005 non-incentive, corporate employee bonus costs assigned to Nebraska were eliminated.

Q. Please continue with the explanation of adjustments.

A. <u>Adjustment No. 10</u> reflects several employee salary increases. First, the impact of merit increases for non-union employees that will become effective March 1, 2007 has been included. These increases will average 3% over current payroll levels and are part of the traditional salary plan for Aquila employees. Secondly, the adjustment includes the impact of a Nebraska union employee payroll increase required per contract for a 2.85 percent annual wage increase effective January 1, 2007. Finally, a 3 percent increase effective January 1, 2007 for call center employees allocated to Nebraska, and an average 2% increase for meter shop employees allocated to Nebraska have been reflected. The merit adjustments and union increases were allocated between utility expense, non-utility expense and payroll capitalized based on the distribution of per book payroll for these categories

Q. Have the corporate staff reductions related to the EOS savings program been reflected in the calculation of the Merit Adjustment and for the Incentive Accrual Adjustment?

A. Yes. The merit and incentive adjustments reflect staff reductions occurring in 2006.

Q. Please continue.

A. Adjustment No. 11 normalizes sales for weather fluctuations experienced during the test year. Support of this adjustment will be provided in the testimony of Aquila's expert witness Mr. Paul Raab.

Adjustment No. 12 reflects the loss of the Omaha Public Power District (OPPD) electric meter reading contract previously held by Aquila, and will be addressed by Mr. Vern Siemek.

Adjustment No. 13 adjusts margins for the impact of bad debts and will be supported by Mr. Glenn Dee.

Adjustment No. 14 Advertising expenses have been adjusted to reflect only those advertising costs associated with informational and safety issues for our customers.

Adjustment No. 15 reflects the reclassification of 50% of Company Contributions from Account 426 ("below the line") to Account 930 ("above the line") expenses, in accordance with past filing procedures. Additionally, 50% of Membership Fees and Dues have been eliminated from utility expenses.

<u>Adjustment No. 16</u> provides the impact of changes in benefit costs. An increase in pension costs is based on the 2006 pension accruals under SFAS 87 –Employers Accounting for Pensions. Mr. Phil Beyer will provide testimony in support of the anticipated increase in pension costs.

Also reflected is an increase in medical costs based on the estimates of 2006 company and employee costs for medical coverage. Ms. Ruth Gustin will provide testimony in support of the anticipated increases in medical costs which affects current Aquila employees in Nebraska, and for AQLCP and NETCO employees who support Nebraska operations.

Q. How were the increased health care costs determined?

A. There are two components of benefit costs. These are self-insured costs and premium based costs. Monthly accounting accruals for medical costs are based on actual claims paid for the self-insured portion, and on the premiums paid to our outside administrator, Hewitt. Both components are then reduced by employee contributions for health care benefits to obtain the net costs incurred by Aquila. The accrual at the end of the test period, June 30, 2006, was annualized and compared to actual expense in order to obtain the health care portion of the increased benefit cost adjustment.

Q. Are there other benefit costs affected by changes in payroll costs?

A. Yes. Aquila provides employees an optional 401(k) benefit plan. Aquila matches funds invested by employees up to 6% of base salary. Aquila also makes an annual contribution of 2 to 4 percent of the employee's salary to the 401(k) plan as part of the Aquila "Profit Sharing Plan". Aquila's contribution to the 401k plan and Profit Sharing Plan and were addressed in the benefit portion of the payroll annualization calculation.

Q. Are there benefit costs Aquila is not including in its rate filing?

A.Yes. Aquila is not proposing recovery of any executive Long Term Incentive Plan costs.

Q. Please continue.

A. <u>Adjustment No. 17</u> Property tax expense was increased to reflect a true-up of actual property taxes paid versus amounts accrued and expensed during the Base Year for the twelve months ended June 30, 2006.

<u>Adjustment No. 18</u> reflects an increase in postage costs resulting from postage increases effective January 1, 2006 and a further increase to become effective January 1, 2007. The increases are offset by a reduction to January to June 2006 actual postage costs that resulted from the allocation changes due to the state property sales by Aquila.

<u>Adjustment No. 19</u> reflects changes in insurance costs and will be supported by Mr. Vern Siemek.

Adjustment No. 20 eliminates the allocated costs in the Base Year associated with lease costs for the "10750" Corporate office building in Raytown, Missouri. The building will be vacated in 2006 as the result of smaller Aquila operations.

Adjustment No. 21 eliminates the 2005 write-off of costs allocated to Nebraska that were related to an abandoned project that had been under development for a Graphical User Interface application for the Call Center. Further work on the project has been terminated.

Adjustment No. 22 is a revenue synchronization that will be supported by Mr. Tom Sullivan.

Q. Does this complete your testimony?

A. Yes.

BEFORE THE NEBRASKA PUBLIC SERVICE COMMISSION

In the matter of Aquila, Inc.	)	
d/b/a Aquila Networks ("Aquila")	)	Docket No. NG-
seeking a general rate increase	)	Docket No. NG-
for Aquila's Rate Areas One, Two	)	Docket No. NG-
and Three (not consolidated)	)	

Direct Testimony of Paul H. Raab

Independent Economic Consultant

Weather Normalization, WNA, RNA and Rate Design

November 1, 2006

Paul H. Raab
4866 Cordell Ave., 3rd Fl.
Bethesda, MD. 20814
301-320-7549

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Paul H. Raab and my business address is 4866 Cordell Avenue, Third Floor, Bethesda, MD 20814. I am an independent economic consultant.

Q. ON WHOSE BEHALF ARE YOU APPEARING TODAY?

A. I am appearing on behalf of Aquila, Inc. (Aquila or the Company).

I. QUALIFICATIONS

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I have a B.A. in Economics from Rutgers University and an M.A. from the State University of New York at Binghamton with a concentration in econometrics. While attending Rutgers, I studied as a Henry Rutgers Scholar.

Q. PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE.

A. I have been providing consulting services to the utility industry for thirty years, having assisted electric, natural gas, telephone and water utilities, Commissions and intervenor clients in a variety of areas. I am trained as a quantitative economist so that most of this assistance has been in the form of mathematical and economic analysis and information systems development. My particular areas of focus are regulatory change management, planning issues, marginal cost and rate design analysis, and depreciation and life analysis. I began my career with the professional services firm that is now known as Ernst & Young, where I was employed for ten years.

Q. HAVE YOU PREVIOUSLY PROVIDED EXPERT TESTIMONY BEFORE THIS COMMISSION?

A. Yes. I have provided expert testimony before this Commission in Case Nos. NG-0001, NG-0002 and NG-0003. I have also provided expert testimony before the state regulatory authorities of the District of Columbia, Georgia, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Montana, Missouri, Nevada, New Jersey, New Mexico, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Virginia, West Virginia and Wisconsin as well as the Federal Energy Regulatory Commission, the Michigan House Economic Development and Energy Committee, the Province of Saskatchewan, and the United States Tax Court.

Exhibit_____(PHR-1) presents more details on the subject matter of the testimony provided.

II. <u>PURPOSE OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony supports four areas of the Company's case. First, I am supporting the weather normalization to test year volumes to adjust for the impact of warmer than normal weather that Aquila experienced in the test year. Next, I am supporting the Company's proposal for a Revenue Normalization Adjustment (RNA), a form of Revenue Decoupling (RD) that will better align the interests of the Company and its customers in the promotion of more efficient use of natural gas. Third, as an alternative to the RNA, I outline a Weather Normalization Adjustment (WNA) Rider that would allow adjustments to sales customers' bills to reflect normal weather. I have been asked by the Company to present the computational details of and theoretical support for this proposed weather normalization adjustment mechanism. Finally, I support the Company's rate design initiatives. These initiatives attempt to provide consumers with a more accurate signal of the cost consequences of their consumption decisions and may be a more efficient RD mechanism for the Company in Nebraska.

Q. WHY IS THE COMPANY PROPOSING AN RNA, A WNA AND RATE DESIGN REFORMS IN THE SAME CASE?

A. The Company's clear preference in this general rate filing is for an RNA because an RNA better serves the interests of Aquila's customers and the

Company. However, Aquila recognizes that RNA mechanisms have not been as widely applied as WNA mechanisms. Therefore, while Aquila proposes that the Commission approve its RNA as part of this general rate filing, it also recognizes that the Nebraska Commission may wish to approve only the WNA, gain experience with it, and later move to an RNA. The WNA may therefore be viewed as an initial step in the direction of a full revenue decoupling mechanism, such as an RNA, that will ultimately provide complete volatility protection for Aquila and its customers. In addition, since both the RNA and WNA are mechanisms that compensate for the shortcomings of rate designs that do not fully reflect the underlying cost of service, either can be implemented as a complement to the Company's rate design proposals and can be phased out as full cost-based rate designs are implemented.

Q. DO YOU HAVE SPECIFIC EXPERIENCE IN DESIGNING, IMPLEMENTING AND EVALUATING RNA CLAUSES?

A Yes. I have assisted Washington Gas in the development of the RNA under which has been operating in Maryland since October 1, 2005. Furthermore, I currently have testimony in Virginia Docket No. PUE–2006–00059 in support of the RNA that Washington Gas has filed in that jurisdiction.

Q. DO YOU HAVE SPECIFIC EXPERIENCE IN DESIGNING, IMPLEMENTING AND EVALUATING WNA CLAUSES?

A Yes. I have assisted in the design of the WNA for Laclede Gas that is currently operating in Missouri, the WNAs for Kansas Gas Service and Aquila that are currently operating in Kansas and the WNA for Oklahoma Natural Gas that is currently operating in Oklahoma. In addition, I have evaluated and supported a number of other WNAs that have been considered for implementation by other natural gas LDCs.

III. <u>IDENTIFICATION OF EXHIBITS</u>

Q. DO YOU SPONSOR ANY EXHIBITS?

A. Yes. I sponsor 12 exhibits. Exhibit_____(PHR-1) is a summary of my qualifications. Exhibit_____(PHR-2) is a summary of the regression equations used to weather normalize test year sales. A summary of the resulting volumetric adjustments to test year sales by class and rate area is provided in Exhibit_____(PHR-3). This exhibit also contains the adjustments to test year revenues corresponding to these volumetric adjustments.

The next three exhibits relate to the Company's proposed RNA proposal. A sample calculation of the proposed RNA adjustment using data from the month of December 2005 is provided as Exhibit_____(PHR-4). Exhibit_____(PHR-5) summarizes the performance of the proposed RNA as if it had been in place since the Company's last rate proceeding, from January 2003 to June 2006. The proposed tariff to implement the RNA is provided as Exhibit_____(PHR-6).

The next five exhibits relate to the Company's WNA proposal. Exhibit_____(PHR-7) compares the "normal" and actual weather for the weather stations used to develop the weather normalization adjustment for calendar year 2003, 2004, 2005 and the first six months of 2006. A summary of an American Gas Association (AGA) survey of weather normalization clauses that have been implemented in other jurisdictions is provided in Exhibit_____(PHR-8). A sample calculation of the proposed WNA adjustment using data from the month of December 2005 and January 2006 is provided as Exhibit_____(PHR-9). Exhibit_____(PHR-10) summarizes the performance of the proposed WNA as if it had been in place since the Company's last rate proceeding, from January 2003 to June 2006. Finally, the proposed tariff to implement the WNA is provided as Exhibit_____(PHR-11).

The final exhibit, Exhibit_____(PHR-12), summarizes all of the data and analysis relevant to the calculation of marginal cost. It is comprised of six schedules. Exhibit_____(PHR-12), Schedule 1 summarizes all of the marginal cost data. This schedule summarizes transmission, distribution, and general plant investments, and customer-related operations and maintenance (O&M) cost data for Aquila for the historical period 1987 to 2005. Price levelized data for these investment and cost categories and years are presented in Exhibit_____(PHR-12), Schedule

2. Operations and Maintenance expenses for the investment cost categories are summarized in Exhibit_____(PHR-12), Schedule 3. The independent variables that drive the costs in the above categories are provided in Exhibit_____(PHR-12), Schedule 4. Exhibit_____(PHR-12), Schedule 5 contains a summary of all of the regressions that are used as the basis for determining the marginal costs. Finally, Schedule 6 of Exhibit_____(PHR-12) summarizes the resulting marginal costs by function.

The above-designated exhibits were prepared by me or under my direction and supervision.

IV. ORGANIZATION OF TESTIMONY

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into five additional sections. Section V provides the computational details behind the weather normalization adjustment to test year sales. Section VI provides both the computational details of and the theoretical justification for the Company's proposed RNA Rider, a form of what is generally referred to as a revenue decoupling (RD) mechanism. Section VII provides a discussion of an alternative to the RNA, a weather normalization adjustment rider. This discussion includes the types of WNA clauses, how they work mechanically, which Companies have applied for WNA clauses (and which have had them accepted or rejected), and if rejected, why. I also discuss the experience that the Company has had with its WNA in Kansas, which was approved by the Kansas Corporation Commission for implementation on October 1, 2003. Next, Section VIII provides theoretical support for the Company's rate design initiatives in this case. My testimony concludes with a summary and recommendations in Section IX.

In addition to these five sections, my testimony includes an Appendix A that summarizes the marginal cost of service study I have developed for Aquila.

V. WEATHER NORMALIZATION ADJUSTMENT

Q. WHY IS IT NECESSARY TO ADJUST TEST YEAR SALES LEVELS FOR THE EFFECTS OF WEATHER?

A. Temperature greatly impacts the amount of natural gas used. Because of this, the Company's earned return in any year can vary significantly, solely as a function of the weather, and test year revenues based on a period of abnormal weather require a weather adjustment for ratemaking purposes. It is unlikely that such abnormalities repeat themselves regularly during the period that the new rates are expected to be in effect. As a result, rates established on such abnormalities would not be likely to produce the revenue levels for which they were designed. It is necessary, therefore, to adjust test year revenues from the sale of gas and the related purchased gas expenses to reflect normal weather.

Q. HOW DID THE WEATHER ACTUALLY EXPERIENCED DURING THE TEST PERIOD COMPARE TO NORMAL WEATHER?

A. The test period was warmer than normal; consequently, it was necessary to add a total of 21,133,114 therms to test year sales volumes and margins of $2,668,412 to reflect the effects of normal weather.

Q. WOULD YOUR PLEASE EXPLAIN THE PROCEDURE USED TO MAKE THE WEATHER ADJUSTMENT?

A. There are a variety of methods that can be used to make this adjustment. However, having performed similar calculations for many natural gas utilities in past cases, I believe that I have applied a method in this case that has broad support in the industry. This method adheres to the following five guidelines:

1. The method employs a level of rate class disaggregation that is as fine as is necessary and can be reasonably supported by the data.
2. The method employs as many weather recording stations as is necessary and can be reasonably supported by the data.
3. “Normal” weather is defined to be the normal weather over a 30 year period established by the National Oceanic and Atmospheric Administration (NOAA).
4. Regression techniques are used to relate usage to an appropriate weather variable. These regression equations are as free as possible from any identifiable statistical impairment.

5. The weather variable employed in the regression specifications is reasonably anticipated to influence usage. In other words, Heating Degree Days (HDDs) are used to normalize those classes that use natural gas for space heating purposes.

Q. HOW DID YOU IMPLEMENT THESE GUIDELINES?

A. First, the average use per customer was established for each of Aquila's rate classes by rate area for January 2003 through June 2006. Next, actual and normal monthly heating degree-days were compiled for the relevant weather stations in Aquila's service territory. Usage per customer for these rate class/rate area/weather station groups was then related to the appropriate weather variable using an ARMA-type model structure that corrects for any autocorrelation problems that are inherent in time series data such as these.

To calculate the weather adjustment from these equations, the NOAA-normal number of HDDs was then applied to the regression equation to obtain the amount of sales that would have occurred had customers experienced normal weather. These volumes are priced at existing rates and the resulting adjustment represents the difference between the weather normalized revenues and the actual test year revenues.

Q. WHAT IS THE SOURCE OF YOUR USAGE DATA?

A. The source of the usage and customer data is the Company. They have provided me with disaggregated usage data that are consistent with that level of usage recorded on the Company's books for the test year. Recorded test year volumes are 385,861,924 therms.

Q. DO THESE DATA ADHERE TO YOUR PRIOR DISAGGREGATION GUIDELINES?

A. Yes, these data are initially compiled at the rate code level, which is the finest reasonable level of disaggregation that is possible.

Q. FROM WHICH STATIONS DID YOU COMPILE THE WEATHER DATA?

A. I compiled weather data from the following three weather stations in Aquila's service territory:

1. Lincoln Airport – National Climatic Data Center (NCDC) Coop. ID No. 254795
2. Norfolk Airport – NCDC Coop. ID No. 255995
3. Omaha Eppley Airport – NCDC Coop. ID No. 256255.

Q. WHY DID YOU USE THESE STATIONS?

A. I used these stations because I believe that they provide a reasonable geographic representation of weather from across the service territory.

Q. ARE THESE THE SAME WEATHER STATIONS THAT HAVE BEEN PREVIOUSLY REVIEWED BY STAFF AND APPROVED BY THE COMMISSION FOR THE PURPOSE OF WEATHER NORMALIZING SALES.

A. Not entirely. While the Lincoln Airport and Omaha Eppley Airport Stations were previously used for this purpose, the Norfolk Airport Station was not used on a stand-alone basis. Rather, it was combined with weather data from Columbus, Fremont, Beatrice and Lincoln Airport to develop a composite weather index to normalize consumption.

Q. WHY DIDN'T YOU CONTINUE THE USE OF THIS SAME COMPOSITE WEATHER MEASURE?

A. I did not continue the use of the "composite" weather measure for three reasons. First, development of a composite weather measure requires the use of judgmental weighting factors. These judgmental factors have the potential to introduce greater error into the weather normalization calculation than is removed by the use of more weather stations, presumably closer to the location where consumption takes place.

Second, there is extremely high correlation among all the stations (in excess of 99.9%). Thus, it is not likely that use of the composite index will introduce a significantly higher degree of accuracy to the weather normalization process.

Third, as discussed later in my testimony, the Company is proposing a weather normalization adjustment rider as an alternative to their preferred RNA. Use of a single station, rather than a composite, will facilitate the periodic audit of the WNA Rider by the Commission Staff, if this proposed option is approved by the Commission.

Q. PLEASE DESCRIBE THE REGRESSION EQUATIONS THAT YOU USED TO DEVELOP THE RELATIONSHIP BETWEEN USAGE AND THE APPROPRIATE WEATHER MEASURE.

A. Regression analysis develops the relationship between a (dependent) variable and one or more independent variables. In this case, the dependent variable is the monthly gas usage of Aquila's customers. The independent variables are the weather effects (HDDs). Thus, the regression equations estimated for this purpose quantify the sensitivity of gas usage to changes in the weather.

The regression equation is specified as:

$$Usage_{i,j,t} = \alpha_{i,j} + \beta_{i,j}(HDD_{j,t}) + \varepsilon_{i,j,t}$$

where:

$Usage_{i,j,t}$ = therm gas usage per customer per month for rate class i and weather station j;

$HDD_{j,t}$ = the actual monthly HDDs at weather station j;

$\varepsilon_{i,j,t}$ = an error term; and

$\alpha_{i,j},\beta_{i,j}$ = estimated coefficients for rate class i and weather station j.

In this case, the coefficient β (sometimes referred to as the heat sensitive factor, or HSF) is of greatest interest since it measures the way that natural gas usage can be expected to change as temperature changes. By extension, β can be used to estimate what consumption would have been had weather been “normal.”

Q. CAN YOU USE THE WEATHER VARIABLES EXACTLY AS PROVIDED BY THE NCDC IN THESE REGRESSION EQUATIONS?

A. No, these data must first be adjusted before they are related to usage.

Q. WHY?

A. Because, due to different meter read cycles, the time period over which monthly usage data is aggregated is not the same time period as the one over which monthly weather data are aggregated. Usage recorded in any month has actually occurred in both that month and the preceding month while weather data for any month actually do represent observations of weather in that month. In order to match the period in which the usage occurs with the period in which the weather that influenced those sales occurs, I include weather from the current month and weather from the preceding month in the regression equations. Thus, the exact functional specifications employed in my analysis are:

$$\text{Usage}_{i,j,t} = \alpha_{i,j} + \beta_{1,I,j}(\text{HDD}_{j,t}) + \beta_{2,i,j}(\text{HDD}_{j,t-1}) + \varepsilon_{i,j,t}$$

Q. WAS THERE A CORRESPONDING WEATHER ADJUSTMENT TO THE CONSUMPTION IN EACH OF THESE WEATHER STATION/RATE CODE GROUPINGS?

A. No. It was not always possible to develop a statistically valid relationship between consumption and the weather variable for two reasons. First, in some cases there simply were not enough observations to develop a meaningful statistical relationship between usage and the appropriate weather variable for that weather station/rate class combination. Second, in some cases, there is no statistically valid relationship between usage and the appropriate weather variable.

Q. WHAT WERE YOUR CRITERIA FOR DETERMINING THE VALIDITY OF THE ESTIMATED RELATIONSHIP?

A. I relied on a battery of commonly applied statistical tests. These tests are:

1. t-test. The t-test is used to determine whether a particular independent variable (in this case, weather) has an influence on the dependent variable (in this case, usage per customer). In other words, it determines whether the selected variable belongs in the regression.
2. R-squared. This is a measure of the success of the regression in predicting the values of the dependent variable within the sample.
3. Log likelihood test. This is the value of the log likelihood function (assuming normally distributed errors) evaluated at the values of

the coefficients. It is often used to select between alternative regression specifications.

4. Durbin-Watson statistic. The Durbin-Watson statistic tests for first-order autocorrelation in the errors, which is the situation where the regression error in one period moves together with the regression error of another. When errors exhibit autocorrelation, the estimated coefficients are not efficient.

5. F-statistic. This statistic tests whether all of the coefficients in a regression are zero. In other words, it tests for the statistical significance of the regression itself.

6. Q-statistics. Q-statistics provide a measure of the autocorrelations and partial autocorrelations of the regression residuals. These statistics provide evidence of autocorrelated disturbance terms and also provide guidance for correcting the autocorrelation.

7. Breusch-Godfrey Serial Correlation Lagrangian Multiplier (LM) Test. This test is a test for general (higher order) serial correlation that uses the Breusch-Godfrey large sample test for autocorrelated disturbances.

8. AutoRegressive Conditional Heteroskedasticity (ARCH) Lagrangian Multiplier (LM) Test. The ARCH LM procedure tests for autoregressive conditional heteroskedasticity, or the tendency for regression errors to move together through time, and be related to some other variable.

Q. HOW DID YOU APPLY THESE TESTS TO YOUR REGRESSION EQUATIONS?

A. I initially used a basic statistical technique called the Ordinary Least Squares (OLS) method to estimate the coefficients of the specified regressions in those cases where sufficient data exist to derive meaningful statistics. I then examined the Q-statistics to determine whether a correction for autocorrelation was needed. If the need for a correction was indicated, I applied an AutoRegressive Moving Average (ARMA) estimation technique to estimate the coefficients. After introduction of the ARMA terms, I tested the models using the Durbin-Watson statistic, the Breusch-Godfrey serial correlation LM test, and the ARCH LM test. After successfully passing these tests, I knew that the weather coefficients that I had estimated were unbiased and of minimum variance, and I proceeded to test whether a valid statistical relationship exists between the dependent and independent variables. For this purpose, I relied primarily on the t-test, the R-squared, the log likelihood test, and the F-test.

Q. UNDER WHAT CIRCUMSTANCES WAS A REGRESSION EQUATION REJECTED USING YOUR TESTING CRITERIA?

A. As an overview, I performed all statistical tests at the commonly applied 95% level of confidence. I did not reject any regression equation if it did not pass the initial tests for serial correlation, but rather used the information from those tests to reduce the serial correlation as much as possible before moving on to tests of the coefficients themselves. With regard to testing the coefficients, I rejected a regression equation if either the t-statistic on the estimated weather coefficient or the F-statistic for the entire regression were not significant at the 95% level of confidence.

Q. HOW MANY REGRESSION SPECIFICATIONS DID YOU ULTIMATELY RELY ON TO PERFORM THE WEATHER NORMALIZATION CALCULATION?

A. I was able to derive a weather normalization adjustment for 16 rate class/rate area/weather station groupings.

Q. WHAT WERE THESE GROUPINGS?

A. The 16 rate class/rate area/weather station groupings I evaluated as well as the estimated values for the intercept and HDD coefficients obtained from the regression analysis for each group are listed in Exhibit_____(PHR-2). This exhibit also contains the results of some of the statistical tests to which I subjected my specifications. All reported coefficients are significant at the 95% level of confidence.

Q. HOW ARE THESE NUMBERS INTERPRETED?

A. As an example, consider the results obtained for residential customers near Omaha in Rate Area 1. Exhibit_____(PHR-2) shows that the estimate for the HDD coefficient is .03986 and for the lagged HDD coefficient is .07302. This means that if the average daily temperature were lower by one degree in the current and preceding month, we would expect consumers in this group to respond to that lower temperature by using approximately .11 more therms of natural gas per customer. Conversely, if the average temperature were one degree higher, then consumers would use .11 less therms of natural gas per customer.

Q. YOU STATED EARLIER THAT THE ESTIMATED COEFFICIENTS b_1 AND b_2 CAN BE USED TO ESTIMATE WHAT CONSUMPTION WOULD HAVE BEEN HAD WEATHER BEEN NORMAL. EXACTLY HOW IS THIS DONE?

A. This is done by using the monthly departure from normal and the regression coefficients. The adjustment formulas for the two general regressions are:

$$\text{WNA} = [(\text{HDD}_t \text{ departure}) * (\text{HDD}_t \text{ Coeff}) + (\text{HDD}_{t-1} \text{ departure}) * (\text{HDD}_{t-1} \text{ Coeff})] * \text{Customers}$$

Q. HOW ARE THE DEPARTURES CALCULATED?

A. Departures, which measure how the test year weather differs from "normal" weather, are calculated by subtracting the actual monthly weather variables for the test year from the normal monthly weather variables for those months. The normal monthly HDDs and CDDs are obtained from the National Climatic Data Center (NCDC) for the 1971 to 2000 time period.

Q. HOW DID YOU COMPUTE THE LEVEL OF REVENUES ASSOCIATED WITH THESE VOLUMETRIC ADJUSTMENTS?

A. For all classes, the Company bills for consumption under a flat rate. Thus, it is a simple matter to calculate the revenue adjustment as the product of the volumetric adjustments and the Company's existing rates.

Q. HAS THIS ADJUSTMENT MECHANISM BEEN USED IN PAST RATE CASES?

A. Yes. This general formula has been used in the prior cases in which I have participated.

Q. AFTER APPLYING THE ABOVE FORMULAS, WHAT ARE THE FINAL RECOMMENDED WEATHER NORMALIZATION ADJUSTMENTS TO THE COMPANY'S TEST YEAR NATURAL GAS SALES?

A. The final adjustment to the Company's actual test year natural gas volumes is 21,133,114 therms. This corresponds to an adjustment to the Company's actual test year margins of $2,668,412. These adjustments are summarized by class and rate area in Exhibit_____(PHR-3).

VI. REVENUE NORMALIZATION ADJUSTMENT (RNA) RIDER

Q. PLEASE DESCRIBE THE RNA RIDER.

A. The RNA Rider is a billing adjustment factor computed on a monthly basis that creates a credit or charge to the monthly delivery charge for firm customers. As the name suggests, the mechanism adjusts for the level of revenues received in a particular month. The mechanism is designed to stabilize the level of revenues that are provided by customers to the Company each month. The agreed upon per-customer revenue level will be determined based on the revenue requirement established in this proceeding.

Q. WHY IS THE COMPANY MAKING THIS PROPOSAL?

A. Aquila, like every natural gas distribution utility, has three types of costs:

1. Customer-related costs – the costs that can be directly assigned to an individual customer (e.g., meters, services, and regulators.
2. Demand-related costs – the costs that vary according to the customer's peak demand (e.g., a portion of mains costs).
3. Commodity-related costs – the costs that vary with usage (e.g., gas costs and the cost of odorant).

Customer-related and demand-related costs represent investments in fixed plant that are made on behalf of customers, the cost of which will be collected from customers over a period of 20-30 years or more. The only commodity-related costs that are billed as base rates are *de minimus.*

Despite the high level of fixed *costs*, gas utility rate structures collect most of the resulting revenues through variable (volumetric) *charges.* As a result, there is a mismatch between cost-incurrence and cost recovery. Because there is a mismatch between the "high fixed cost" cost structure faced by an LDC and the significant amount of revenues that are currently collected through volumetric charges, reductions in volumes do not necessarily translate into reductions in costs. Therefore, any volumetric changes faced by Aquila have unnecessarily stressed its finances, pressure for rate relief has been greater than it would have been had rate structures been more closely aligned with cost structures and consumers have paid higher bills as a result.

Q. IF THE PRIMARY CAUSE OF HIGHER RATES TO CONSUMERS IS A MISMATCH BETWEEN THE UTILITY'S COST STRUCTURE AND THE UTILITY'S RATE STRUCTURE, WHY NOT SIMPLY FIX THE RATE DESIGN PROBLEM?

A. This is being done with increasing frequency today, as witnessed in Georgia and North Dakota. It is also the underlying rationale for the Company's alternative rate design proposals in this case. However, many regulatory authorities desire to continue existing practices wherein the result of the adopted cost allocation and rate design would appear to be in favor of the smaller users. This is true both across rate classes and within rate classes. This translates into the reluctance of many regulatory authorities to move customer charges to levels consistent with the levels of fixed costs identified in traditional class cost of service studies. The Company's RNA and WNA proposals are an attempt to resolve the rate design/underlying cost conflict, while at the same time maintaining the current system of intra-class cost recovery.

Q. HOW WILL THE RNA CREDIT OR CHARGE BE DETERMINED?

A. The RNA credit or charge is determined in four simple steps, a sample calculation of which is provided with my testimony as Exhibit_____(PHR-4). Exhibit_____(PHR-4) provides an example of a monthly RNA calculation for December 2005 that would have been applied to bills rendered in February 2006.

The first step is to determine a monthly test year amount of revenues based on the final order in this case. This is shown on lines 2-5 of page 1 of Exhibit_____(PHR-4). The second step is to calculate a customer growth adjustment. Sample calculations for the individual customer classes and rate areas are provided in pages 2 through 7 of Exhibit_____(PHR-4). As an example, the customer growth adjustment calculation for residential customers in rate area 1 (shown on page 2 of Exhibit_____(PHR-4)) is done by taking the difference between the current month number of customers (line 5) and the number of customers in the corresponding month of the test year (line 4) to arrive at the change in number of customers (line 6). The resulting number is multiplied by the current customer charges (line 7) to arrive at the customer charge revenue impact (line 8). Next, the delivery charge impact is calculated by multiplying the monthly test year average number of therms per customer (line 10) by the change in the number of customers for that month (line 11) to calculate the change in therms (line 12). The change in therms is multiplied by the delivery charge per therm (line 13) to arrive at the volumetric charge revenue impact (line 14). The total customer growth adjustment (line 15) is calculated by adding the customer charge revenue impact and the delivery charge revenue impact.

Third, the required revenue adjustment is calculated as shown on line 12 of page 1 of Exhibit_____(PHR-4). The monthly test year customer charges (line 3) and delivery charges (line 4) are added together to arrive at the monthly test year base revenue (line 5). The customer growth adjustment (line 6) is then added to the monthly test year base revenue to calculate the target base revenue (line 7). The customer charges (line 9) and delivery charges (line 10) for the month are also added together to arrive at the actual calendar month base revenue (line 11).

Finally, the actual calendar month base revenue (line 11) is subtracted from the monthly target base revenue (line 7) to calculate the required revenue adjustment (line 12).

Q. WHEN WILL THE ADJUSTMENT BE APPLIED?

A. The RNA adjustment will be calculated and applied to customers' bills on a two-month lag basis. That is, the adjustment for any given month will occur on bills rendered two months later. For example, the adjustment for January 2008 will occur in the bills sent out in the March 2008 billing cycle. In addition, the workpapers detailing the RNA adjustment will be forwarded to the Commission Staff at least ten days prior to the start of the billing cycle where it will be applied.

Q. HOW DOES THE RNA BENEFIT CUSTOMERS?

A. The weather normalization component of the RNA benefits customers since it mitigates the impact of abnormal weather on utility bills. During periods of colder-than-normal weather, the weather normalization component would benefit customers through reduced delivery charges. This treatment aligns the Company's level of revenues with the normal weather level that is the basis for its distribution rates. From the customer's perspective, the delivery charge relief provided during periods of colder-than-normal weather is helpful especially given the current environment of significant gas commodity price volatility.

Q. PLEASE DESCRIBE THE CUSTOMER GROWTH ADJUSTMENT.

A. The customer growth adjustment is a key element of the RNA calculation. It utilizes a test year average therm use per customer, which is applied to the change in the number of customers from the test year level. By adjusting for the number of customers that have been added on a net basis, it provides greater confidence that the resulting revenue benchmark is reflective of current conditions.

Q. WHAT IMPACT WOULD THE RNA HAVE HAD IF IT HAD BEEN IN PLACE SINCE THE LAST BASE RATE PROCEEDING?

A. In order to demonstrate how the proposed RNA mechanism would work, I have simulated the performance of the RNA since the Company's last base rate case. The simulation is developed on a monthly basis from the test year in that case (the twelve months ended December 31, 2002) through June 2006. These results are summarized in Exhibit_____(PHR-5).

The exhibit shows that, while there have been months in which Aquila did collect that level of revenues consistent with the Commission's determination in the last case, in no calendar year has Aquila ever collected that level of revenues consistent with the Commission's determination in the last case. Specifically, the Company under-collected Commission-authorized revenue levels in calendar year 2003 by $444,571. This figure has risen consistently since then to $1,998,388 in calendar year 2004, $2,543,870 in calendar year 2005 and $4,176,558 in the first six month of 2006.

This persistent shortfall is significant in the context of the current case for two reasons. First, my analysis does not incorporate costs, which have generally been rising to reflect three and one-half years of investments and inflation. Thus, the Company's financial position was worse than projected by this simulation. Second, these revenue shortfalls are the result of two factors: weather and conservation, neither of which is subject to management control. Thus, Aquila's shareholders are being financially penalized for circumstances completely outside of management control.

This underscores an important reason for implementation of an RNA in this context: the significant mismatch between the fixed cost nature of the business and the volumetric emphasis of the utility's rate structures. An RNA mechanism realigns the collection of revenues to the incurrence of costs.

Q. ARE THERE OTHER REASONS WHY IT IS APPROPRIATE TO STABILIZE REVENUES WITH THESE TYPES OF MECHANISMS?

A. Yes. The conflict between cost incurrence and cost recovery creates significant disincentives for utilities to promote conservation. These disincentives can be removed if the sales of natural gas can be "decoupled" from the level of throughput. Thus, RNA mechanisms are sometimes referred to as revenue decoupling mechanisms.

Q. WHAT IS THE BASIC RATIONALE FOR REVENUE DECOUPLING MECHANISMS?

A. There are three basic reasons that argue for a revenue decoupling mechanism in this context. First, because sales levels are so dependent upon weather variations or conservation activities outside of management control, it makes little sense to reward the Company with higher revenues simply because it is cold or people choose not to replace an inefficient furnace. Second, depending on the degree to which the rate structure is "out of synch" with the Company's cost structure, minor variations in usage can have significant financial consequences for the utility. As can be seen from the embedded cost of service study performed by Company Witness Thomas J. Sullivan, over 95% of the Company's costs to serve its customers can be characterized as "fixed" in the short run, i.e., they are either customer-related or demand-related costs. In contrast, under current rates, about 50% of the Company's distribution revenues are obtained through volumetric charges. Thus, there is a significant mismatch between the Company's cost and rate structures. And finally, the probability that sales levels will deviate from weather-normal sales levels is virtually 100%. Thus, without some form of revenue decoupling mechanism, there is a virtual certainty that one party (either the utility or its customers) will be disadvantaged.

Q. WHAT VOLUMETRIC RISK IS THE COMPANY'S RNA PROPOSAL INTENDED TO ADDRESS?

A. Besides the volumetric risk associated with weather, there has been a documented and long-term decline in usage per customer in the United States and on the Aquila system in Nebraska specifically that has placed additional pressure on Company earnings. This pressure on earnings can lead to greater frequency of rate cases than would otherwise be the case.

Q. IN GENERAL, WHAT HAS BEEN THE TREND IN NATURAL GAS USAGE PER RESIDENTIAL CUSTOMER?

A. On February 11, 2000, the American Gas Association (AGA) published Patterns in Residential Natural Gas Consumption Since 1980. That report indicates that nationally, natural gas use per residential customer dropped 16 percent from 1980 to 1997 from 106 thousand cubic feet (Mcf)/year to 89 Mcf/year. The Midwest saw even more dramatic declines over this period of almost 18%, from 142 Mcf/year to 116 Mcf/year.

When the AGA updated its analysis and published the results in Patterns in Residential Natural Gas Consumption, 1997-2001, a similar pattern emerged: national consumption down an additional 6.4% to 83.5 Mcf per residential customer per year and Midwestern consumption down an additional 8.1% to 107 Mcf per residential customer per year.

Q. WHAT ARE THE CAUSES OF THIS DECLINE?

A. In order of importance, the AGA reports cite the following factors:

1. Space heating efficiency gains. Federal efficiency guidelines set the minimum efficiency of new natural gas furnaces at 78 percent, up from an average efficiency of 65 percent in 1980.
2. Water heating efficiency gains. Similarly, Federal water heater standards, which took effect in 1990, set the minimum efficiency factor of water heaters at .54, up from .50 during the 1980s.
3. Space heating market share loss. This was primarily a factor in warmer climates where heat pumps captured a significant share of the market.
4. Baseload appliance market share loss. The market shares of water heaters, cooking appliances and gaslights all declined, and were not fully off set by increased market shares of clothes dryers and gas logs.
5. Improved home energy efficiency. Not only were more energy efficient homes built, but older homes were retrofitted with insulation and storm doors and windows so that the thermal integrity of heated building shells was improved. In addition, the amount of heated floor space per residence declined.
6. Demographic changes. Population shifted to warmer climates and the number of people per household fell. While not specifically cited in the AGA reports, the number of people working out of the

home could also have contributed to these declines.

Q. ARE THESE SAME FACTORS AT WORK IN NEBRASKA?

A. They clearly are, and have manifested themselves in Aquila's usage per residential customer figures. Since the last case, weather-normalized residential usage in Aquila's Nebraska service territory has dropped from 808 therms/year to 716 therms/year, a reduction of over 11%.

Q. HAVE THESE FACTORS "PLAYED THEMSELVES OUT" OR ARE THEY LIKELY TO CONTINUE TO AFFECT NATURAL GAS USAGE IN THE FUTURE?

A. While the impact of these factors will tend to lessen through time, it is clear that they will still influence natural gas consumption in the future. AGA estimates that an additional 10% reduction in residential usage per customer will occur between 2001 and 2020. (<u>Forecasted Patterns in Residential Natural Gas Consumption, 2001-2020</u>, September 21, 2004) The same factors will affect usage, but the reductions will occur "at a slower pace than experienced in the past two decades."

In this regard, it is important to note that these studies were performed during a time of significantly lower commodity prices. To the extent that current, higher commodity prices cause a new round of demand reductions as a result of increased efficiency improvements and fuel switching, the AGA estimates may overstate future consumption levels and understate price-induced demand reductions.

Q. ARE THE SAME TRENDS APPARENT AND THE SAME FACTORS AT WORK IN THE NON-RESIDENTIAL SECTORS?

A. Yes. As the AGA documented in Trends in the Commercial Natural Gas Market, October 23, 2002, use per commercial customer declined 18 percent nationally from 1979 to 1999. In the Midwest these declines were even more pronounced, reflecting reductions in commercial usage per customer of almost 27%.

Q. AREN'T THE IMPROVEMENTS IN ENERGY EFFICIENCY AND THE RESULTING REDUCTIONS IN USAGE PER CUSTOMER UNQUALIFIED GOOD NEWS?

A. There are certainly many positive aspects to this phenomenon. Natural gas consumption at the end-use level has become much more efficient and natural gas bills to consumers have been significantly reduced from what they would have been absent the efficiency improvements. Furthermore, the reduction in usage has caused natural gas LDCs to reduce operations and maintenance expenses in order to maintain a level of earnings that will support their financial health. However, there are two not so obvious negatives associated with these rosy reports:

1. Because there is a mismatch between the "high fixed cost" cost structure faced by an LDC and the significant amount of revenues

that are currently collected through volumetric charges, reductions in volumes do not necessarily translate into reductions in costs. Therefore, LDC finances have been unnecessarily stressed and pressure for rate relief has been greater than it would have been had rate structures been more closely aligned with cost structures.

2. It is not clear that all of the reductions in gas volumes that have occurred are in the best economic interests of society. To the extent that inefficient pricing has caused fuel switching that would not occur for underlying economic reasons, what appears to be conservation is not, in the broader context of overall energy consumption.

Q. HAS AQUILA SUFFERED FROM THESE NEGATIVES IN NEBRASKA?

A. Certainly the first one. As described above, over 95% of the Company's costs to serve its customers can be characterized as "fixed" in the short run, while about 50% of the Company's distribution revenues are obtained through volumetric charges. Solely as a result of this mismatch between prices and cost incurrence, the Company does not fully recover its fixed costs during periods of warmer than normal weather. This is clearly demonstrated in the simulation of Exhibit_____(PHR-5).

Q. HOW COMMON ARE RNA-TYPE MECHANISMS?

A. Five natural gas LDCs are operating under RNA-type mechanisms in four different jurisdictions. These utilities are Baltimore Gas & Electric and Washington Gas in Maryland, Southwest Gas in California, Northwest Natural Gas in Oregon and Piedmont Natural Gas in North Carolina. However, as of the drafting date of this testimony, another ten utilities had filed for approval of such mechanisms in six jurisdictions. These utilities are Cascade Natural Gas, Puget Sound Energy and Puget Energy in Washington State, Questar Gas in Utah, Citizens Gas and Coke Utility and Vectren Energy Delivery in Indiana, Vectren Energy Delivery in Ohio, New Jersey Natural Gas and South Jersey Gas in New Jersey and Washington Gas in Virginia. Thus, by the time that the Nebraska Commission decides on this issue for Aquila, it is possible that as many as twenty percent of the states will have already approved such mechanisms for the LDCs that they regulate.

Q. HAVE THESE MECHANISMS BEEN ENDORSED BY REGULATORY AUTHORITIES?

A. In addition to the four regulatory authorities cited above that have specifically endorsed mechanisms such as the Company's proposed RNA, NARUC endorsed these mechanisms at its 2005 Fall Meeting in Palm Springs, CA:

RESOLVED, That the Board of Directors of NARUC encourages state commissions and other policy makers to consider in their review

> innovative rate designs including “energy efficient tariffs” and “decoupling tariffs” (such as those employed by Northwest Natural Gas in Oregon, Baltimore Gas & Electric in Maryland, Washington Gas in Maryland, Southwest Gas in California, and Piedmont Natural Gas in North Carolina), “fixed-variable” rates (such as that employed by Northern States Power in North Dakota, and Atlanta Gas Light in Georgia), “customer choice options” (such as that approved in Oklahoma for Oklahoma Natural Gas), and other innovative proposals and programs that may assist, especially in the short term, in promoting energy efficiency and energy conservation and slowing the rate of growth of natural gas…

Q. THIS RESOLUTION STATES THAT RNA-TYPE MECHANISMS CAN ACTUALLY PROVIDE LDCS WITH INCENTIVES TO PROMOTE CONSERVATION. HOW DOES THIS OCCUR?

A. Under a traditional, volumetric-based rate, utilities must increase consumption to maintain their financial health. This is particularly true given the persistent declines in usage per customer that I discussed previously. RNA mechanisms such as the one proposed here provide a stronger incentive for utilities to promote conservation because they “decouple” the utility’s volumetric sales from its profitability. Thus, the utility is not penalized in the form of decreased earnings for encouraging the efficient use of natural gas.

Q. HAVE OTHER REGULATORY AUTHORITIES RECOGNIZED THIS DISINCENTIVE?

A. I believe that regulators have long recognized this inherent defect in traditional rate designs and have recently begun to adopt regulatory policies to overcome this disincentive. For example, in 2003 the Oregon

Public Utility Commission approved a "conservation tariff" for Northwest Natural Gas Company "to break the link between an energy utility's sales and its profitability, so that the utility can assist its customers with energy efficiency without conflict." The conservation tariff seeks to do that by using modest periodic rate adjustments to "decouple" recovery of the utility's authorized fixed costs from unexpected fluctuations in retail sales. (See Oregon PUC Order No. 02-634, Stipulation Adopting Northwest Natural Gas Company Application for Public Purpose Funding and Distribution Margin Normalization, September 12, 2003).

In California, natural gas distribution utilities have a long tradition of investment in energy efficiency services, including those targeting low income households, and the Commission is now considering further expansion of these investments along with the creation of performance-based incentives tied to verified net savings. California also pioneered the use of modest periodic true-ups in rates to break the linkage between utilities' financial health and their retail gas sales, and has now restored this policy in the aftermath of their industry restructuring experiment.

Also consistent with the notion that traditional ratemaking discourages natural gas utilities from promoting conservation, Southwest Gas Company received an order from the California PUC in March 2004 that authorizes it to establish a margin tracker that will balance actual margin revenues to authorized levels.

Q. DO OTHER INDUSTRY GROUPS RECOGNIZE THIS DISINCENTIVE?

A. Yes. In July 2004, the American Gas Association and the Natural Resources Defense Council issued a joint statement to the National Association of Regulatory Commissioners that was intended to identify "ways to promote both economic and environmental progress by removing barriers to natural gas distribution companies' investments in urgently needed and cost-effective resources and infrastructure," and encourage regulators to consider "innovative programs that encourage increased total energy efficiency and conservation in ways that will align the interests of state regulators, natural gas utility company customers, utility shareholders, and other stakeholders." The primary problem that the Joint Statement identifies is what it refers to as the "Energy Efficiency Problem," under which utilities are "penalized" for aggressively promoting energy efficiency. According to the Statement, the penalty results from the same mismatch of (fixed) costs and (volumetric) rates that I have identified earlier for Aquila:

> The vast majority of the non-commodity costs of running a gas distribution utility are fixed and do not vary significantly from month to month. However, traditional utility rates do not reflect this reality. Traditional utility rates are designed to capture most of approved revenue requirements for fixed costs through volumetric retail sales of natural gas, so that a utility can recover these costs fully only if its customers consume a minimum amount of natural gas (these amounts are normally calculated in rate cases and generally are based on what consumers consumed in the past). Thus, many states' rate structures offer – quite unintentionally – a significant financial disincentive for natural gas utilities to aggressively encourage their customers to use less natural gas, such as by providing financial incentives and education to promote energy-efficiency and conservation techniques.

> When customers use less natural gas, utility profitability almost always suffers, because recovery of fixed costs is reduced in proportion to the reduction in sales. Thus, conservation may prevent the utility from recovering its authorized fixed costs and earning its state-allowed rate of return.

Q. HAS THE COMPANY MADE A TANGIBLE COMMITMENT TO CONSERVATION IN THIS CASE?

A. Yes. As described in the testimony of Company Witness Daunis**,** the Company plans to spend approximately $850,000 per year to promote natural gas usage efficiency. The dual benefits of this commitment are promoted through the Company's RNA proposal.

Q. ARE THERE OTHER REASONS THAT ARGUE IN FAVOR OF THE IMPLEMENTATION OF RNA MECHANISMS?

A. Yes. In addition to the benefits cited above, RNA mechanisms can also: (a) provide consumers with a more accurate price signal of the consequences of their consumption decisions, (b) result in more stable rates for consumers and more stable revenues for the Company, and (c) provide benefits to low income consumers.

Q. HOW CAN A RATE STRUCTURE THAT INCLUDES AN RNA PROVIDE CUSTOMERS A MORE ACCURATE PRICE SIGNAL THAN A RATE STRUCTURE THAT DOES NOT INCORPORATE AN RNA?

A. Because the vast majority of an LDC's distribution-related costs are fixed and a majority of its revenues are collected through volumetric charges, an LDC collects revenues in excess of costs when it is colder than normal. With an RNA in place, this over collection is passed back to consumers. Without an RNA in place, consumers are signaled through prices that higher consumption causes the LDC to incur higher costs. This is simply not an accurate signal.

Q. WHY IS IT IMPORTANT THAT CONSUMERS ARE PROVIDED WITH A MORE ACCURATE PRICE SIGNAL OF THE CONSEQUENCES OF THEIR CONSUMPTION DECISIONS TO USE MORE OR TO USE LESS?

A. There are those who believe that less use of natural gas is an unqualified good thing. However, as an economist, I am trained to believe that conservation for conservation's sake is not the answer. It is the job of a rate structure to provide the correct price signal. Consumers can then use the cost information contained in the rate and make consumption tradeoffs between the cost of energy and the costs of durable goods to make economically efficient consumption decisions, which may even result in more consumption of natural gas. In this context, signaling consumers that the consumption of more distribution service has significant cost consequences when it is colder than normal is misleading and unwise when all cost bases for all economic time horizons indicate this not to be the case.

Q. HOW DOES AN RNA MECHANISM PROVIDE MORE STABLE AND PREDICTABLE RATES FOR AQUILA CUSTOMERS?

A. Rate stability and predictability are often referred to as rate continuity. In the context of this rate proposal, there are two dimensions to rate continuity. The first is the degree to which rates remain stable and predictable as they are being implemented. Implementation of the RNA will have no negative initial consequences, simply by virtue of the fact that rates themselves have not changed.

The second dimension to rate continuity is the degree to which rates remain stable and predictable after they are implemented. In this case, a rate structure with an RNA is also vastly superior to a rate structure without an RNA, because the impact of weather and conservation on customer bills is effectively eliminated.

In addition, under the traditional rate design, these rates are the highest in the coldest winters, when natural gas prices are also likely to be higher. Thus, after implementation, not only will rates be more stable and more predictable for customers, but they could also produce additional benefits in the form of lower arrearages and less disconnects.

Q. HOW CAN THE RNA PROVIDE MORE STABLE AND PREDICTABLE REVENUES FOR AQUILA?

A. As discussed above, revenue stability and predictability will be enhanced under an RNA because the resulting bills better reflect cost causation so that as volumes change as a result of conservation, efficiency gains or warm weather, the revenues and costs will be more synchronized.

Q. HOW CAN THE RNA BENEFIT LOW INCOME CONSUMERS?

A. The fact that the distribution price is effectively "capped" in the winter months will make it easier for all customers, particularly low-income consumers who have a higher energy *burden* than non low-income consumers, to pay their bills. This should reduce arrearages and eventually lead to lower rates for all customers on the system.

Furthermore, as discussed above, the RNA proposal provides for more stable bills, at least for the distribution-related portion of the bill. This will provide a benefit to all of the customers on the system who are on fixed incomes, generally the elderly and low-income consumers.

Q. WHY WILL "CAPPED" DISTRIBUTION RATES IN THE WINTER MONTHS MAKE IT EASIER FOR LOW INCOME CUSTOMERS TO PAY THEIR BILLS?

A. Because the customers' bills for distribution service will not be influenced by weather.

Q. AND WHY IS THIS A GOOD THING?

A. As Roger D. Colton states in Payment-Problems, Income Status, Weather and Prices: Costs and Savings of a Capped Bill Program:

> Irrespective of the unaffordability of home energy during “normal” times, one additional question is whether low income customers, and the companies that serve them, can beneficially insulate these customers from the vagaries of weather and price-induced spikes in annual and seasonal home energy bills. After the confluence of cold weather and a fly-up in natural gas prices during the 2000/2001 winter heating season in much of the nation, an increasing number of industry observers recognize the harms that arise from extraordinary changes in bills accompanying spikes in price and/or temperature.

While gas costs will still vary according to the weather, these costs are determined by the market and not by the Commission. Therefore, if the Commission approves the proposed RNA, it will have done what it can to stabilize the prices under its control.

Q. WHY WILL “CAPPED” DISTRIBUTION RATES IN THE WINTER MONTHS REDUCE ARREARAGES AND EVENTUALLY LEAD TO LOWER RATES FOR ALL CUSTOMERS ON THE SYSTEM?

A. The previously cited study by Colton also provides the answer to this question. While Colton discusses a lack of empirical data to assess the exact degree to which weather influences the level of arrears, his evaluation of Iowa utility data shows that:

1. There is a strong association between the dollars of arrears for energy assistance accounts at the end of the heating season and the temperatures experienced during the heating season.

2. There is a strong association between the dollars of arrears for energy assistance accounts at the end of the heating season and the bills experienced during the heating season.

This means that if the strong association between winter temperatures and bills can be weakened, the dollars of arrears for energy assistance accounts will be lower at the end of any given heating season.

Q. WHAT ARE THE ARGUMENTS AGAINST SUCH MECHANISMS?

A. Seven arguments have been advanced in opposition to the adoption of RNA mechanisms. These are:

1. There is a need for the utility to demonstrate special circumstances in order for the Commission to approve a true up of revenues.
2. It is inappropriate to adjust revenues alone between rate cases without also considering the level of expenses.
3. If the Commission approves an RNA, there is less likelihood that the very real problems of the utility's rate design will ever be addressed.
4. The benefits to customers and the utility are unequally distributed.
5. An RNA is likely to place upward pressure on short-term distribution rates.
6. An RNA is an overly broad solution to the utility's revenue problem.
7. An RNA reduces risk and should be accompanied by a reduction in the Commission's authorized ROE in this case.

Q. DO YOU AGREE THAT THERE IS A NEED FOR THE UTILITY TO DEMONSTRATE SPECIAL CIRCUMSTANCES IN ORDER FOR THE COMMISSION TO APPROVE A TRUE UP OF REVENUES?

A. Yes I do. However, I also believe that such circumstances have been clearly demonstrated. As discussed above, conservation has made the achievement of the Commission's authorized rates of return consistently over a sustained period of time unlikely. Further, requiring the Company to play a "weather lottery" that has increasingly become stacked against it creates a circumstance whereby achievement of the Commission's authorized rate of return is difficult.

Q. DO YOU ALSO BELIEVE THAT IT IS INAPPROPRIATE TO ADJUST REVENUES ALONE BETWEEN RATE CASES WITHOUT ALSO CONSIDERING THE LEVEL OF EXPENSES?

A. No. The RNA operates in exactly the same way that the weather normalization adjustment to test year revenues in this case. When applying that adjustment, there is no corresponding adjustment to test year distribution costs, in explicit recognition of the fact that volume changes do not translate into cost changes.

Q. IF THE COMMISSION APPROVES AN RNA, IS THERE LESS LIKELIHOOD THAT THE VERY REAL PROBLEMS OF THE UTILITY'S RATE DESIGN WILL EVER BE ADDRESSED?

A. That is certainly possible. However, the Company recognizes this concern by proposing both the RNA and various increases in customer charges as a beginning step in the ultimate correction of the rate design problem. The Company views the ultimate movement to a single, cost-based rate design for each class as the best solution to the financial challenges that it will likely face in the future. Such a proposal is in the long-term best interests of the Company, its customers and society. However, historical intra-class cost shifts and rate shock concerns may limit the speed with which these benefits can be achieved. As a result, the Company will be faced with significant financial risks outside of management's control that must be mitigated. The Company's RNA is the mechanism that it is proposing to mitigate that risk.

Q. ARE YOU SAYING THAT THE RNA WILL BE ELIMINATED WHEN THE RATE DESIGN PROBLEM HAS BEEN FIXED?

A. Yes, when that problem has been fully addressed, there will be no more need for the RNA and the more quickly the Company can achieve cost-based rate designs, the sooner the RNA can be eliminated.

Q. ARE THE BENEFITS FROM AN RNA UNEQUALLY DISTRIBUTED BETWEEN CUSTOMERS AND THE UTILITY?

A. No. While the timing of the allocation of the benefits is changed, both the utility and its customers will benefit from the RNA proposal.

Q. PLEASE EXPLAIN.

A. The RNA does not change the level of costs incurred by the utility. Because the utility is authorized to collect this level of costs, it will do so under traditional ratemaking principles with a lag, plus applicable carrying charges or it will do so under an RNA on a more timely basis. Thus, the benefits and costs to customers are the same whether the utility has an RNA in place or is operating under traditional ratemaking.

Q. IS AN RNA LIKELY TO PLACE UPWARD PRESSURE ON SHORT-TERM DISTRIBUTION RATES?

A. Based on current market conditions, I would agree that there will likely be upward pressure on short-term distribution rates. Demand growth is slowing due to conservation and higher commodity prices and significant investments for distribution integrity management programs are looming. However, the RNA is not to blame.

Q. IS AN RNA AN OVERLY BROAD SOLUTION TO THE UTILITY'S REVENUE PROBLEM?

A. Perhaps, but in the absence of real rate design reform, it is the <u>only</u> solution that will provide the utility with an opportunity to generate a level of revenues that is consistent with the Commission's authorized returns.

Q. DO YOU AGREE THAT ADOPTION OF AN RNA SHOULD BE ACCOMPANIED BY A REDUCTION IN THE COMMISSION'S AUTHORIZED ROE IN THIS CASE?

A. No. An ROE reduction as a result of implementing the RNA would be inappropriate for at least five reasons:

1. Comparable companies employ risk management strategies – Many comparable companies already incorporate measures to mitigate risk. Therefore, to not allow some sort of risk mitigation will penalize Aquila by not affording them risk protection, but awarding them an ROE that assumes they already have it.

2. Inability to measure – The required ROE cannot be measured precisely enough to reflect in the impact of ROE reduction from these measures (i.e., the ROE band is generally wider than any reduction to ROE ever suggested by any party. Therefore, the ROE impact of any reduced risk may already be reflected in the allowed ROE.)

3. Inability to measure – No one has been able to develop a defensible measure of the impact that such a mechanism has on ROE. And, it could be positive (less revenue risk) or negative (the uncertainty associated with a rate increase). Therefore, any adjustment that the Commission makes is arbitrary and could in fact be exactly the opposite of what should be done.

4. Too removed from the test year – Any impact from the RNA will not be immediately felt. Therefore, the Board is violating its own practices by going well beyond the test year if it makes an adjustment for the RNA. When the impacts are known, they will be reflected in an upcoming test year's data and can be incorporated at that time. (This was FERC's rationale when they approved SFV rate designs in Order No. 636.)

5. Bad Public Policy - Customers will see benefits from the RNA mechanism as discussed above (more stable bills through time, lower costs, a more financially sound utility and greater incentives to promote energy efficiency). To "punish" the utility for bringing these benefits to consumers seems ill advised.

Q. PLEASE SUMMARIZE YOUR TESTIMONY REGARDING THE COMPANY'S RNA PROPOSAL.

A. The Company is proposing to implement an RNA in this case because the factors that are causing significant volatility in sales levels are outside of management control, because the Company's rate structure is "out of synch" with the Company's cost structure and because the chances of achieving the Commission's authorized ROE in this case are diminished without it. These types of mechanisms are becoming commonplace, special circumstances warrant Commission approval of a true up of revenues, and the Company's proposal considers both revenues and expenses for adjustment. Furthermore, Aquila proposes a solution to its rate design problems and customers and the utility will benefit equally from the proposal. The RNA will not place upward pressure on short-term prices and the RNA is the <u>only</u> solution that will provide the utility with a level of revenues that is consistent with the Commission's authorized returns. Finally, adoption of the RNA should not be conditioned upon a reduction in authorized ROE in this case for reasons cited above.

Q. HAVE YOU PREPARED A SAMPLE TARIFF TO SUPPORT THE IMPLEMENTATION OF THE PROPOSED RNA?

A. Sample tariff language is provided as Exhibit_____(PHR-6).

VII. <u>THE WNA CLAUSE</u>

Q. WHAT ARE WEATHER NORMALIZATION ADJUSTMENT MECHANISMS?

A. Weather normalization adjustment (WNA) mechanisms are ratemaking tools that can offset the impact of unusually warm or unusually cold weather on a gas company's operating revenues and earnings. They work by utilizing an adjustment factor that increases or decreases base rates to compensate for deviations from normal weather.

Gas rates charged by local distribution companies (LDCs) are predicated in part on an assumption of anticipated gas throughput. Because throughput, particularly for heating customers, is highly weather sensitive, deviations from the weather conditions assumed in the development of those rates ("normal" weather) can lead to deviations in revenues and earnings. Indeed, because weather has been at record warm levels in the United States for many of the recent past winters, sales and earnings of LDCs have been significantly stressed.

Exhibit_____(PHR-7) shows just how different actual weather conditions can be from "normal" weather conditions. The exhibit compares annual actual and normal HDDs for the three stations used to weather normalize test year volumes for 2003, 2004, 2005 and the first six months of 2006. Two conclusions are apparent from this comparison. First, at no time since rates were last set have actual degree-days been greater than or equal to the NOAA "normal" degree-days. Second, there is an apparent trend in the data portrayed on the exhibit such that the deviations from normal are increasing over time. This is causing significant financial stress on the Company, again through no fault of Aquila management.

Q. HAVE OTHER GAS LDCS IMPLEMENTED WNA MECHANISMS?

A. Yes. In the summer of 1990, the AGA Rate Committee sponsored a survey of rate adjustment mechanisms that provide revenue stability in the event of abnormal weather conditions. The results of that survey were published by AGA in June 1991, and subsequently updated in September 1992, December 1994 and April 2000. To my knowledge, these surveys represent the most comprehensive evaluation of WNA clauses to date and are longitudinal in nature so that experience with WNA's can be tracked through time. In addition, these surveys appear to capture the features of such clauses that are in place today and represent a reasonable sample of those LDCs that have applied for a WNA clause, both successfully and unsuccessfully.

Q. WHAT ARE THE KEY FINDINGS OF THE AGA SURVEY?

A. There are three key findings of the AGA survey work: (1) there are two general types of WNA clauses, (2) there are four key differences in the operation of WNA clauses, and (3) many LDCs have applied for and implemented WNA clauses.

Q. PLEASE DESCRIBE THE TWO TYPES OF WEATHER NORMALIZATION CLAUSES.

A. In what AGA refers to as a type (1) WNA, revenue adjustments to compensate for abnormal weather are added directly to the customer's monthly bill. A type (2) WNA, on the other hand, captures the revenue deviations in a deferred account and collects (or refunds) the difference over future sales.

Q. PLEASE DESCRIBE THE FOUR KEY DIFFERENCES IN THE OPERATION OF WNA CLAUSES.

A. The AGA report identifies four areas in which differences in the application of the WNA arise: the number of months over which the WNA will operate (all months, heating season only, or some combination); volumes covered (sales customers only, all weather-sensitive customers, all customers); threshold levels at which the WNA applies (±0.5%, ±2.2%); and timing of the adjustment (one month delay, immediate application).

Q. HOW MANY LDCS HAVE IMPLEMENTED WNA CLAUSES?

A. When AGA conducted its first survey in 1991, 10 LDCs had operating WNA clauses and another 10 LDCs had applied. By the time of the last survey in April 2000, 43 WNA clauses were in operation, 3 were under consideration, and 14 had been denied, dismissed, or dropped as part of a rate settlement. Only 4 LDCs had terminated their WNA clauses. This information is summarized in Exhibit_____(PHR-8).

Q. WHAT REASONS ARGUE FOR THE IMPLEMENTATION OF A WNA?

A. One can argue for the implementation of a WNA because it provides benefits to both the customer and the Company.

Q. WHAT BENEFITS DOES THE WNA PROVIDE TO CUSTOMERS?

A. The primary benefit that a WNA provides to customers is bill stability. This program would benefit customers by moderating winter bills in colder than normal periods. Since such periods are often characterized by both greater consumption and higher gas prices, the program provides customers with financial relief, just when they need it the most. As noted by the Wyoming Commission in its Order in Docket No. 30010-GR-96-35:

> [The WNA] has the benefit of shielding customers from rate spikes for non-gas costs which would otherwise occur during periods of cold weather. During periods when the weather is colder than normal, customers will pay less than they would under standard, non-adjusted rate schedules.

Q. WHAT BENEFIT DOES THE WNA PROVIDE TO THE COMPANY?

A. The primary benefit is revenue stability.

Q. HOW DO YOU RESPOND TO ARGUMENTS THAT WITH A WNA IN EFFECT, CUSTOMERS ARE BEING CHARGED FOR GAS THAT THEY DID NOT USE?

A. Such a statement reflects a lack of understanding of how rates are set in a regulatory arena. Since rates are based on volumes but the bulk of a utility's costs are fixed, a WNA allows the utility to recover its (fixed) costs during the period in which the service is rendered. Thus, customers are charged not for the gas that they did not use, but for the service that they did receive.

To summarize, WNA clauses can be regarded as a win-win situation for the utility and its customers.

Q. IF WNA CLAUSES PROVIDE BENEFITS TO ALL PARTIES, WHY HAVE THEY BEEN DENIED?

A. Those who oppose WNA's do so because they are alleged to cause customer confusion, lead to an increase in administrative costs, and send potentially misleading price signals. In addition, some argue that the necessary data to support the implementation of a WNA are not available and that the Companies' proposals should be accompanied by a reduction in return to reflect lower risk.

Q. HOW COULD A WNA LEAD TO CUSTOMER CONFUSION?

A. It is argued that, if the WNA were separately identified as a line item on the bill, it would lead to customer confusion as to why this charge appears on the bill. If the WNA were not identified on the bill, customers would be confused as to why the rate changes every month.

Q. HOW DO YOU RESPOND TO THIS FIRST CONCERN THAT THE WNA WILL LEAD TO CUSTOMER CONFUSION?

A. As with any rate change, the Company will have an obligation to educate consumers. However, historical experience has shown that after the consuming public has experience with a new rate or structure, it is ultimately understood and accepted. For example, the Company's PGA varies periodically with little understanding of why it does so by the consuming public, and this does not cause significant customer confusion today.

I would also note that Aquila has had a WNA operating in Kansas since October 2003 and that the WNA factor is specifically identified on customers' bills. Aquila management has indicated to me that they have seen no discernible increase in the number of inquiries as a result of the implementation of the WNA.

Q. HOW DO YOU RESPOND TO THE SECOND CONCERN THAT THE WNA WILL INCREASE ADMINISTRATIVE COSTS?

A. I have specifically discussed this issue with Aquila management personnel who implemented their WNA in Kansas over three years ago and they inform me that they have observed no incremental administrative costs as a result of the implementation of their WNA.

Q. HOW CAN THE WNA POTENTIALLY SEND MISLEADING PRICE SIGNALS?

A. In an economic sense, the "proper" price signal during any time period or season is the marginal cost. If the Company's costs do not increase at the same rate as consumption (since they include fixed costs, we know that they do not), then the marginal cost at high consumption levels will be less than the price charged at those consumption levels and an unnecessarily high price signal will be sent to consumers. A higher than economically efficient price signal leads to a set of consumption and resource allocation distortions that are not necessarily less serious than a lower than economically efficient price.

In other words, economic theory suggests that the WNA provides a more theoretically correct price signal than the price signal sent under a traditional flat rate.

Q. DOES AQUILA HAVE THE HISTORICAL DATA TO PROPERLY IMPLEMENT THE WNA?

A. Yes. As will be described more fully below, the Company intends to utilize the same data that are used to weather-normalize natural gas sales for budgeting and ratemaking purposes to implement the WNA. Thus, Aquila is relying on the same data that are currently and have previously been employed in the rate setting process.

Q. HOW DO YOU RESPOND TO THE CONCERN THAT THE COMPANY'S WNA PROPOSAL SHOULD BE ACCOMPANIED BY A REDUCTION IN RETURN ON EQUITY TO REFLECT LOWER RISK?

A. WNA clauses are becoming such a common element of the LDC ratemaking landscape that it is doubtful that a list of comparable companies for the purpose of developing a required return on equity could be developed which did not include LDCs that have already implemented WNA's. Accordingly, if WNA's do reduce weather-related financial risk, then utilities without WNA's, such as Aquila, could be disadvantaged if they are compared to allegedly less risky companies with WNA's.

Q. PLEASE DESCRIBE A WNA THAT IS CONSISTENT WITH THE FINDINGS AND CONCLUSIONS ABOVE AND THAT CAN BE IMPLEMENTED BY THE COMPANY.

A. In light of the above discussion, the Company's proposed WNA will incorporate the following general features:

1. <u>The Company will implement what has been termed a type 1 weather normalization clause</u>. From the AGA survey described above, there are two types of weather normalization clauses that could be proposed in this case. A type 1 clause collects any deficiency or refunds any over collection related to weather during the period over which the deficiency or over collection is identified. A type 2 clause defers the over- and under-collections, and

recovers them in some future period. A type 1 clause will do a better job of stabilizing customer bills and revenues and is also easier to implement than a type 2 clause since there is no need to true up the collections over a number of periods with a type 1 clause.

2. <u>Weather normalization will be performed using the same factors that are used to develop normal weather therm sales in this case</u>. These factors are summarized in Exhibit_____(PHR-2).

3. <u>The WNA will apply to all months of the year</u>. The AGA survey indicates a varying number of months during which the WNA can apply. However, a primary concern is that it be consistent with the weather normalization process of this rate case. This implies that the clause will operate for all twelve months of the year, although there will be little or no adjustment in the June to September period.

4. <u>The clause will apply to the same rate classes whose sales are weather normalized during the case</u>. The primary reason for this feature is to make it consistent with the rate case.

5. <u>The Company will collect/refund the revenue difference in a separate rider, applied to the volumetric charges of each rate</u>. There are at least three possible ways to collect the revenue deficiency from or return the excess collections to customers: (1) in the delivery rate itself; (2) in its own rider; or (3) in the Purchased

Gas Adjustment (PGA) factor. Aquila proposes to implement its WNA as a separate factor, applied on a volumetric basis.

Q. PLEASE DESCRIBE THE SPECIFIC ELEMENTS OF THE PROPOSED WNA.

A. The above discussion provides the general framework of the WNA. In order to assist the Commission to see exactly how the adjustment would be calculated, I have prepared Exhibit_____(PHR-9). This exhibit shows a sample calculation for a residential customer in Rate Area 1 for the January 2006 bill assuming the customer has a read date of January 15 and there are thirty-one days in the cycle. As can be seen from the exhibit, the following five steps implement the proposed WNA:

1. For each customer and cycle, calculate the actual degree-days, normal degree-days and difference between normal degree-days and actual degree-days for the current billing month and the prior billing month. Using the assumptions above, the difference is 88 HDDs in December and 202 HDDs in January, as shown on page 1 of Exhibit_____(PHR-9).
2. Calculate the volumetric adjustment for each customer using the same formula as used to weather normalize test year volumes for ratemaking purposes. As shown on page 2, line 17 of Exhibit_____(PHR-9), this adjustment is 14.48 therms under the assumptions listed there.

3. Calculate the simulated volumes for each customer using the base load, heat sensitive factors and actual weather. This is calculated to be 68.86 therms under the assumptions listed on Exhibit_____(PHR-9).

4. Calculate the WNA factor as the appropriate delivery service rate times the ratio of the volumetric adjustment and the simulated volumes. Using this ratio ensures that the sum of the customer- and cycle-specific weather normalization adjustment will always equal the total weather normalization adjustment calculated on a system basis and used for ratemaking purposes.

5. Calculate the WNA amount to be collected from this individual customer as the product of the WNA factor and actual volumes.

Q. WHAT WOULD HAVE BEEN THE IMPACT OF THE WNA RIDER HAD IT BEEN IN PLACE SINCE THE COMPANY'S LAST BASE RATE PROCEEDING?

A. To answer this question, I have prepared Exhibit_____(PHR-10). Exhibit_____(PHR-10) calculates the amount by which the Company's actual revenues have deviated from the revenues that it could have expected had weather been normal. These normal weather revenues are the level of revenues that the Commission expected the Company to earn as a result of their last rate order. As can be seen, actual monthly revenues were both greater than and less than normal weather revenues over this time period. However, because of the significantly warmer than normal weather experienced by the Company in Nebraska, a serious revenue shortfall occurred. Specifically, the Company under-collected Commission-authorized revenue levels in calendar year 2003 by $175,169. This figure has risen consistently since then to $1,121,102 in calendar year 2004, $1,830,443 in calendar year 2005 and $2,143,173 in the first six month of 2006.

Q. PLEASE DESCRIBE THE WNA RIDER THAT THE COMPANY WILL IMPLEMENT TO COLLECT THE DEFICIENCIES OR REFUND THE OVER COLLECTIONS AS A RESULT OF WEATHER.

A. Exhibit_____(PHR-11) contains the tariff that is necessary to implement the Company's proposed WNA. It incorporates all of the features described above.

Q. WHAT FILING REQUIREMENTS WOULD YOU RECOMMEND TO PROVIDE COMMISSION STAFF AND OTHER INTERESTED PARTIES WITH AN OPPORTUNITY TO AUDIT THE CALCULATIONS OF THE COMPANY?

A. Because of the volume of information needed to audit the WNA calculations, I would recommend that the Company file summary information that includes the deviation from normal weather for the month and the deviations from weather-normalized revenues for each customer class and rate area to which the WNA Rider applies.

VIII. THE PROPOSED RATE DESIGNS

Q. PLEASE DESCRIBE THE COMPANY'S CURRENT RATE DESIGNS.

A. The Company's current rate designs are traditional two-part rates with a fixed monthly (customer) charge and a volumetric (commodity) charge. The current rates are as follows:

Summary of Existing Rate Designs		
Class	Customer Charge ($/customer/month)	Commodity Charge ($/therm)
Rate Area 1:		
Residential	$11.00	$0.10967
Commercial	$15.00	$0.12700
Energy Options - Firm	$15.00	$0.12700
Rate Area 2:		
Residential	$11.00	$0.11070
Commercial	$15.00	$0.15922
Energy Options - Firm	$15.00	$0.15922
Rate Area 3:		
Residential	$11.00	$0.12177
Commercial	$15.00	$0.15266
Energy Options - Firm	$15.00	$0.15266

In addition to the above delivery charges, customers must pay for the natural gas that they consume and must pay any applicable taxes and other charges.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED RATE DESIGNS.

A. The Company is making three rate design proposals in this case: (1) a traditional two-part rate design that equalizes charges across rate areas and increases both customer charges and commodity charges, (2) a traditional two-part rate design that equalizes charges across rate areas but increases only customer charges to achieve the requested level of revenues in this case and (3) a simple, one-part rate design that equalizes customer charges across rate areas. The following summarizes all of these rate design proposals:

Summary of Proposed Rate Designs		
Class	Customer Charge ($/customer/month)	Commodity Charge ($/therm)
Proposed Rate Design:		
Residential	$16.00	$0.14868
Commercial	$20.00	$0.15803
Energy Options - Firm	$20.00	$0.15803
Alternative 1 – Increase in Customer Charges:		
Residential	$18.07	$0.11409
Commercial	$21.96	$0.15139
Energy Options - Firm	$21.96	$0.15139
Alternative 2 – Equalized Customer Charges:		
Residential	$29.01	$0.00000

Commercial	$29.01	$0.00000
Energy Options - Firm	$29.01	$0.00000

Q. WHY IS THE COMPANY MAKING THE ALTERNATIVE PROPOSALS?

A. Both of the alternative rate design proposals made by the Company in this case have the effect of providing customers with a price signal that is more closely aligned with the Company's underlying cost structure. This has benefits to customers, the Company and to society, as I will explain in greater detail below. Furthermore, as discussed by Kenneth Costello, Senior Institute Economist of the National Regulatory Research Institute in his Briefing Paper, <u>Revenue Decoupling for Natural Gas Utilities</u>:

> "Alternatives to RD in achieving the same objectives might be preferable, as RD is a more blunt approach than most alternatives. These alternatives can include: (1) raising the customer charge by removing fixed costs from the volumetric charge…" <u>Revenue Decoupling for Natural Gas Utilities</u>, page 19.

Q. ARE THE RATE DESIGN PROPOSALS "PREFERABLE" RD MECHANISMS, AS SUGGESTED BY COSTELLO?

A. They may be. Properly designed rates can solve the same problems as the RNA, and provide the following additional benefits:

1. The alternative rate design proposals remove fixed cost recovery from volumetric charges and thereby more closely reflect the Company's underlying cost of service. This statement is true whether one uses an embedded cost standard or a marginal cost standard.

2. The alternative rate structure proposals will actually provide stronger incentives for the utility to promote conservation than will the traditional rate structure.

3. Under the Company's alternative rate design proposals, the distribution price is less volatile in the winter months, making it easier for customers to pay their bills. This should reduce arrearages and eventually lead to lower rates for all customers on the system.

4. The Company's alternative rate design proposals also provide for more stable annual bills, at least for the distribution-related portion of the bill. This will provide a benefit to all of the customers on the system who are on fixed incomes, generally the elderly and low-income consumers.

Q. CAN THIS BE DEMONSTRATED?

A. Yes. In this section of my testimony I demonstrate how the rate design alternatives provide these benefits. I first discuss the Company's underlying embedded cost structure as identified in the class cost of service study sponsored by Company Witness Sullivan. I then provide an evaluation of how the alternatives provide the benefits identified above.

a. Class Cost Of Service Study Results

Q. PLEASE DESCRIBE THE COMPANY'S CLASS COST OF SERVICE STUDY PREPARED BY WITNESS SULLIVAN.

A. Company witness Sullivan has prepared and sponsors a class cost of service study that first groups costs by function (gas supply demand, gas supply commodity, transmission demand, transmission commodity, distribution demand, distribution commodity, distribution customer, services, meters and regulators, and customer accounts). The functionalized costs are then allocated to the different customer classes being studied using a variety of allocation factors such as the number of customers, throughput and peak demand as appropriate.

Q. DO YOU BELIEVE THAT MR. SULLIVAN'S STUDY FORMS A PROPER BASIS FROM WHICH RATES CAN BE DESIGNED?

A. Yes. In my opinion, the study is sound and provides a reasonable starting point from which to design rates (as he has done) and then to evaluate those rates (as I do and document in my testimony). However, in my analysis, it is also important to classify the costs into those that are customer-related, those that are demand-related and those that are commodity-related. I develop these classifications, although the overall cost of service and the cost of service by class developed by Mr. Sullivan and myself are exactly the same.

Q. HOW DO YOU DEVELOP THESE CLASSIFICATIONS?

A. The appropriate classification is apparent from Mr. Sullivan's allocation factors. For example, Mr. Sullivan allocates certain transmission costs on the basis of annual throughput. Therefore, I classify these costs as commodity-related. All of the classifications I employ can be summarized as follows:

Function	Classification
Gas Supply Demand	Demand
Gas Supply Commodity	Commodity
Transmission Demand	Demand
Transmission Commodity	Commodity
Distribution Demand	Demand
Distribution Commodity	Commodity
Distribution Customer	Customer
Services	Customer
Meters & Regulators	Customer
Customer Accounts	Customer

Q. PLEASE DESCRIBE THE VARIOUS TYPES OF COSTS THAT YOU HAVE IDENTIFIED FROM THE CLASS COST OF SERVICE STUDY USING THE ABOVE CLASSIFICATION STRATEGY.

A. At the overall return of 9.60%, the embedded class cost of service study develops an overall cost of service (excluding gas costs) of $66,966,824.

Of this total, $54,318,479 (81% of the total cost of service) is classified as customer-related, or is incurred simply to serve customers. The demand-related portion, or the amount that is classified according to the volumes of natural gas that customers require on the peak day is $9,104,076 (14% of the total). Finally, the commodity-related portion, or those costs classified according to the amount of natural gas that customers consume annually is $3,544,270 (5% of the total). This means that those costs that are considered to be "fixed" in the total cost of service comprise 95% of the total cost to serve.

Q. IS THIS AN UNUSUAL RESULT?

A. No. Based on my experience, the finding that the bulk of the Company's non-gas costs are fixed is typical. Furthermore, support for this general conclusion can be found in publications of the National Association of Regulatory Utility Commissioners (NARUC). For example, the NARUC Manual on <u>Gas Rate Design</u>, August 6, 1981, shows the following functional breakdowns of a natural gas LDC's major expenses:

TABLE III

TYPICAL FUNCTIONAL BREAKDOWN – GAS SYSTEM

Production plant & purchased gas cost	D,E
Storage plant	D
Transmission plant	
Mains	D
Compressor stations	D
Distribution Plant	
Mains	D,C
Measuring & Regulating Stations	D,C

Services	C
Meters & Regulators	C
General plant	D,C
Customers' accounting & collecting expenses	C
Sales promotion expenses	D,C
Administrative & general expenses	D,C

(C = Customer Costs)
(D = Demand Costs)
(E = Energy Costs)

Source: NARUC Manual on Gas Rate Design, August 6, 1981, page 28.

As can be seen from this exhibit, the only commodity-related costs that are identified in the NARUC Manual are those related to the acquisition of natural gas. Thus, the only surprise from the Company's results is that any commodity-related costs have been identified at all, since the Company figures cited above specifically exclude natural gas costs.

b. The Proposed Rate Designs

Q. PLEASE DESCRIBE HOW THE ALTERNATIVE RATE DESIGNS MORE ACCURATELY MATCH THE COMPANY'S UNDERLYING COST OF SERVICE.

A. The following table summarizes the percentage of revenues or costs that are considered "fixed." For the Cost of Service, "fixed" costs are those that are classified as either customer-related or demand-related as described above. For the rate design alternatives, "fixed" costs are those that are collected through customer charges.

Fixed/Variable Portion of Cost or Rate		
	Fixed Portion	Variable Portion

Cost of Service	95%	5%
Traditional Proposal	57%	43%
Increased Customer Charges	64%	36%
Flat Rate	100%	0%

This comparison makes it clear that either of the alternative rate design proposals will do a significantly better job of providing consumers with the true cost consequences of their consumption decisions than will the Company's traditional rates. This is important because, as I discussed earlier, natural gas usage has historically declined and is forecasted to continue to decline. As a result, existing volumetric-based rate designs will increasingly under-collect Commission-authorized levels of revenues and put financial pressure on the Company.

Q. THE ABOVE DISCUSSION IS BASED ON EMBEDDED COSTS. WHEN DISCUSSING THE TRUE COST CONSEQUENCES OF CONSUMPTION DECISIONS, SHOULDN'T YOUR STANDARD OF COMPARISON BE MARGINAL COSTS?

A. Yes, and when we compare the Company's rate structures to its marginal costs of providing service, the case for the alternative rate designs is even more compelling. Appendix A to my testimony describes a marginal cost of service study I have conducted for Aquila. On a system basis, I have developed the following marginal cost estimates:

Marginal Cost of Service Summary
Aquila, Inc.

Cost Component	Marginal Cost Estimate
Transmission	$3.71/customer/month
Common Distribution	$17.28/customer/month
Customer-Specific Distribution	$17.88/customer/month
Customer-Related O&M	$8.43/customer/month

As described more fully in the Appendix, I estimated these marginal costs by first developing a total cost equation for each of the Company's major cost functions in which annual cost is a linear function of a cost driver (the number of customers served, the peak demand on the system or the annual throughput or sales). The cost driver ultimately selected for each function was chosen because it resulted in the best regression statistics, specifically t-statistics and R-squared values. Thus, the cost driver associated with each function is the one that best explains the investment in each of the evaluated cost categories.

All of the results are summarized in Schedule 5 of Exhibit_____(PHR-12). Five functions were evaluated (Transmission Plant; Common Distribution Plant; Services, Regulators and Meters; General Plant and Customer Accounting Costs) using five independent variables that were considered as candidate cost drivers (Customers, the three commodity-related variables of Gas Received, Gas Delivered and Annual Sales and Peak Day demand). For each functional cost/independent variable combination, the estimated coefficient is provided as well as the R-squared value associated with the regression equation.

In order to select the best cost driver, I first eliminated any functional cost/independent variable combination that did not yield a significant independent variable coefficient. In other words, I did not evaluate any equation further that did not evidence a statistically significant relationship. Then, I chose among the remaining relationships based on R-squared values of the regression equations.

For example, a statistically significant relationship is estimated between customer-related operations and maintenance expenses and the number of customers and annual sales cost drivers. I chose the best driver to be the number of customers served, since this variable is demonstrated to best explain the variation in these costs with an R-squared of over 82%.

Q. WHAT DOES THIS ANALYSIS OF THE COMPANY'S LONG-RUN MARGINAL COSTS INDICATE ABOUT THE COMPANY'S COMPETING RATE DESIGN PROPOSALS?

A. It provides two important pieces of information. First, it indicates that those rate structures that include more fixed charges will more closely reflect the underlying marginal cost of providing natural gas distribution service. Other things being equal, such rate designs should produce a more economically efficient consumption outcome than the Company's current rate designs that are more heavily weighted toward commodity-related charges. Second, it indicates that, in the long-run, natural gas distribution costs are more driven by the number of customers served than any other factor. Thus, a rate structure that relies heavily on fixed (customer and demand) charges does not encourage uneconomic long-run consumption decisions. Rather, it encourages economically efficient consumption decisions that will, by definition, discourage socially undesirable levels of consumption.

Q. IS YOUR FINDING THAT CUSTOMER GROWTH IS THE DOMINANT FACTOR IN THE GROWTH OF GAS DISTRIBUTION COSTS CORROBORATED BY ANY OTHER INDEPENDENT RESEARCH?

A. Yes. Recent research by Lowry, Getachew and Fenrick found the same strong relationship between natural gas distribution utility cost increases and customer growth. Describing their econometric analysis of the 42 LDCs in the United States from 1993-2000, the authors conclude:

> These results suggest that gas distribution cost is, in the long run, much more sensitive to growth in the number of customers served than to growth in throughput. This finding clearly contrasts with the way that output growth typically affects base rate revenue. Mark Newton Lowry, Lullit Getachew, and Steven Fenrick, "Regulation of Gas Distributors with Declining Use per Customer," Dialogue, pp. 17-27.

Q. SINCE THE PROPOSED RATE DESIGNS ARE SO HEAVILY DOMINATED BY FIXED CHARGES, WILL THEY DISCOURAGE THE COMPANY FROM PROMOTING ECONOMICALLY EFFICIENT CONSERVATION?

A. No. As described above, rate structures that are dominated by fixed charges will actually provide stronger incentives for the utility to promote conservation than will rate structures that rely heavily on volumetric charges. This is not only my position, but the position of such disparate groups as the National Association of Regulatory Utility Commissioners, the American Gas Association, the Natural Resources Defense Counsel and various state regulatory authorities throughout the country. Furthermore, because the charges better match the costs of providing service, consumers receive a more accurate price signal of the consequences of their consumption decisions to use more or to use less. As the discussion above makes clear, this latter statement is true from both an embedded and a marginal standpoint in both the short-run and the long-run.

Q. DO OTHERS SHARE YOUR VIEW THAT A RATE STRUCTURE THAT IS DOMINATED BY FIXED CHARGES PROVIDES STRONGER INCENTIVES FOR THE UTILITY TO PROMOTE CONSERVATION THAN A RATE STRUCTURE THAT RELIES HEAVILY ON VOLUMETRIC CHARGES?

A. Yes. In an October 2004 article in American Gas magazine, the Honorable Stan Wise, then president of the National Association of Regulatory Utility Commissioners, writes:

> The simple and rational step of aligning costs with the right type makes sense because of the economics of the industry, and it

makes sense because it increases the opportunity to make conservation work. It may be as simple as a higher customer charge, thus reducing the connection between revenue and throughput.

Q. YOU MENTIONED IN AN EARLIER ANSWER THAT THE PROPOSED RATE DESIGNS WILL ALSO PROVIDE CONSUMERS WITH A MORE ACCURATE PRICE SIGNAL OF THE CONSEQUENCES OF THEIR CONSUMPTION DECISIONS TO USE MORE OR TO USE LESS. WHY IS THIS IMPORTANT?

A. As described above, it is the job of a rate structure to provide the correct price signal. Consumers can then use the cost information contained in the rate and make consumption tradeoffs between the cost of energy and the costs of durable goods to make economically efficient consumption decisions, which may even result in more consumption of natural gas. In my opinion, signaling consumers that the consumption of more distribution service has significant cost consequences is misleading and unwise when all cost bases for all economic time horizons indicate this not to be the case.

Q. DO YOU ADVOCATE THAT ALL COSTS BE BILLED THROUGH NON-VOLUMETRIC CHARGES?

A. No. Both of the Company's proposed rate structures still bill per therm gas costs so that, even under the flat charge proposal, over 70% of charges are billed on a volumetric basis.

Q. WHICH OF THE RATE STRUCTURES PROVIDES MORE STABLE AND PREDICTABLE RATES FOR AQUILA'S CUSTOMERS?

A. Since the customer bills that result from the alternative rate designs are much less subject to the vagaries of the weather than customer bills from traditional rate designs, the new rate designs are vastly superior to the existing rate designs under this criterion. In addition, under the traditional rate design, these rates are the highest in the coldest winters, when natural gas prices are also likely to be higher. Thus, after implementation, not only will these proposed rate designs be more stable and more predictable for customers, but they could also produce additional benefits in the form of lower arrearages and less disconnects.

Q. HOW DO THE COMPANY'S RATE DESIGN PROPOSALS FARE WHEN EVALUATED BASED ON THEIR IMPACT ON LOW INCOME CONSUMERS?

A. Since the alternative proposals increase monthly fixed charges and decrease volumetric charges relative to the Company's traditional rate design, they will definitely increase bills for smaller users relative to traditional rate designs and decrease bills for larger users relative to traditional rate designs. Thus, to answer the incidence question, one needs to know the relationship between income level and consumption level, i.e., are low-income consumers also low volume consumers, or are they high volume consumers. If low-income consumers are also high volume consumers, then they will benefit (in the form of reduced bills) from the Company's proposal. On the other hand, if they are low volume consumers, then they will pay higher bills under the Company's proposal.

To determine whether consumption levels are positively or negatively related to income, three methods can be used. The first method is to conduct a survey of customers. This method is not extremely reliable as customers are understandably reluctant to share information regarding income with third parties and I have not applied it in this case. The second method relies on economic theory to develop conclusions about the relationship between income and consumption, and recognizes that this relationship is nothing more than an income elasticity. Specifically, since the income elasticity measures the responsiveness of the quantity demanded of a good or service to income levels, all one need do is develop an income elasticity for natural gas consumption for the relevant group of consumers. If the income elasticity developed is positive, this indicates that, as income rises, the consumption of natural gas will also rise. If the income elasticity is negative, this indicates that, as income rises, the consumption of natural gas will decline and, it follows that low-income consumers are higher volume consumers of natural gas.

Finally, the third method collects data on the income characteristics and consumption experience of consumers at the household level.

Q. HAVE YOU DEVELOPED AN INCOME ELASTICITY FOR NATURAL GAS CONSUMPTION IN NEBRASKA?

A. Not personally. However, elasticity estimates have been developed in a recent (1997) empirical study of the relationship between natural gas consumption and income, published as "Estimation of Short-Run and Long-Run Elasticities of Energy Demand From Panel Data Using Shrinkage Estimators," in the Journal of Business and Economic Statistics, January 1997, Volume 15, No. 1. This article, authored by G. S. Maddalla, Robert P. Trost, Hongyi Li, and Frederick Joutz, describes the estimation of price and income elasticities for each of 49 states in the United States using data for 21 years. The study described by this article represents the most recent estimation of which I am aware of short- and long-run elasticities of natural gas demand that are both econometrically correct and geographically comprehensive.

With respect to the income elasticities derived, this article contains the following conclusion:

> The long-run income elasticity for natural gas is persistently estimated as negative with the individual OLS regressions and is nearly 0 (-.057) with the shrunken estimates. Although it seems counterintuitive that the long-run natural gas income elasticity is smaller than the short-run natural gas elasticity, there are several explanations for this result. First, as incomes rise, households may buy microwave ovens and will substitute away from gas cooking into microwave cooking. Second, as incomes rise, households may convert their homes to central air conditioning and households that previously used gas for heating now have the option of converting to electric heating and cooling with a heat pump. Hence, a certain subset of these households will reduce their gas consumption dramatically as incomes rise. Third, as incomes rise, households will remodel their homes. In many cases

> the configuration of appliances such as ranges, clothes dryers, and water heaters after remodeling are not convenient to gas lines. Again, a subset of households that previously used gas for these end uses will now convert to electricity as incomes rise. Finally, natural gas price controls had an impact on the availability of supplies…The combination of these factors can explain the income elasticity results. (Maddalla, Trost, Li, and Joust at 98.)

Q. WHAT DOES THIS MEAN?

A. It means that, according to empirical research, it is more likely that high volume users of natural gas are lower income consumers.

Q. DID YOU COLLECT DATA ON THE INCOME CHARACTERISTICS AND CONSUMPTION EXPERIENCE OF CONSUMERS AT THE HOUSEHOLD LEVEL?

A. Again, I did not personally do so, but I relied on available government studies that collect data at this level of detail.

Q. WHAT SPECIFIC STUDIES DID YOU REVIEW?

A. Three studies of which I am aware develop a detailed survey based relationship between income and natural gas usage: the Department of Energy (DOE)/Energy Information Administration (EIA) publication entitled *Natural Gas Usage in American Households*, the *LIHEAP Home Energy Notebook*, and the U.S. Department of Labor, Bureau of Labor Statistics annual Consumer Expenditures Survey.

Q. AND WHAT DO THESE STUDIES SHOW?

A. These studies compile data at the national level and show only modest increases in expenditures for natural gas as income rises.

Q. BASED ON THIS INFORMATION, WHAT DO YOU CONCLUDE WITH RESPECT TO THE COMPANY'S RATE DESIGN CHANGE PROPOSAL?

A. It is not possible to unequivocally answer the incidence question. However, while the available evidence may lead to conflicting conclusions about the relationship between income and natural gas usage, one thing is unequivocal: low income consumers have a higher energy *burden* than non low income consumers.

Q. BASED ON THIS INFORMATION, WHAT DO YOU CONCLUDE WITH RESPECT TO THE COMPANY'S ALTERNATIVE RATE DESIGN PROPOSALS?

A. Low-income consumers could benefit more from the Company's alternative rate design proposals than from the Company's traditional rate design proposals because the alternatives more closely coincide with the load they place on the distribution system. Furthermore, this rate design will provide the following additional significant benefits to low-income consumers:

1. The fact that the distribution price is less volatile in the winter

months will make it easier for all customers, regardless of income level, to pay their bills. This should reduce arrearages and eventually lead to lower rates for all customers on the system.

2. The rate design proposal provides for more stable annual bills, at least for the distribution-related portion of the bill. This will provide a benefit to all of the customers on the system who are on fixed incomes, generally the elderly and low-income consumers.

Q. WILL BOTH OF THE COMPANY'S ALTERNATIVE RATE DESIGN PROPOSALS PROVIDE FOR MORE STABLE BILLS?

A. Yes, because, under either proposal, the level of the customer's bill will be less influenced by weather variations from year to year.

Q. HOW WILL THIS PROVIDE A BENEFIT TO ALL OF THE CUSTOMERS ON THE SYSTEM WHO ARE ON FIXED INCOMES?

A. It will help them to budget their energy expenditures more effectively. This could also help the Company to manage its arrearages and provide benefits to all customers on the system.

IX. SUMMARY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony describes a Company and an industry that are facing financial difficulties due to external influences that are completely beyond their control. In an attempt to minimize the financial consequences of these influences, the Company has made three proposals in this case: an RNA, a WNA and alternative rate designs. While each of these proposals will have a different impact on the problem, the Company's preference is for an RNA with limited rate design changes.

Q. WHY DOES THE COMPANY FAVOR THE RNA?

A. The Company favors the RNA because the factors that are causing significant volatility in sales levels are outside of management control, because the Company's rate structure is "out of synch" with the Company's cost structure and because the chances of achieving the Commission's authorized ROE in this case are diminished without it.

Q. WHY SHOULD THE COMMISSION APPROVE THE RNA IN THIS CASE?

A. The Commission should approve the RNA rather than the WNA in this case because these types of mechanisms are becoming commonplace and special circumstances warrant Commission approval of a true-up of revenues. Furthermore, Aquila's customers and the utility will benefit equally from the proposal. The RNA will not place upward pressure on short-term prices and the RNA is the <u>only</u> solution that will provide the utility with a level of revenues that is consistent with the Commission's authorized returns.

Should the Commission be unwilling to implement a full RNA, it may wish to at least consider the Company's proposed WNA.

Q. WHY WOULD THE COMMISSION APPROVE THE WNA IN THIS CASE?

A. For many of the same reasons that it should approve the RNA. It is needed if the Company is to have any chance of earning the return authorized by the Commission in this proceeding. Aquila's customers and the utility will benefit equally from the proposal. Furthermore, these types of mechanisms are already commonplace and to not approve such a mechanism for Aquila will actually penalize Aquila since most comparable companies already have some form of weather protection.

Q. WHY DOES THE COMPANY FAVOR THE ADOPTION OF AN RNA OVER THE WNA?

A. As demonstrated above, the Company has experienced a significant amount of conservation in Nebraska. This argues for the adoption of the RNA over the WNA if the Company is to have any opportunity at all to earn the Commission authorized rate of return in this case. Furthermore, the RNA calculations will be significantly easier for the Commission Staff to audit than the WNA calculations.

Q. WHAT RATE DESIGN CHANGES DO YOU RECOMMEND THAT THE COMMISSION ADOPT?

A. I recommend that the Commission move toward Aquila's Alternative 2. This alternative more closely reflects the Company's underlying cost of service whether one uses an embedded cost standard or a marginal cost standard. It will provide stronger incentives for the utility to promote conservation than will the traditional rate structure. It will provide a distribution price that is less volatile in the winter months, making it easier for customers to pay their bills. This should reduce arrearages and eventually lead to lower rates for all customers on the system. The rate design will also provide for more stable annual bills, at least for the distribution-related portion of the bill. This will provide a benefit to all of the customers on the system who are on fixed incomes, generally the elderly and low-income consumers. Finally, if the Commission fully approves the Company's Alternative 2, it will not be necessary to implement either the RNA or WNA proposal.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY AT THIS TIME?

A. Yes.

BEFORE THE NEBRASKA PUBLIC SERVICE COMMISSION

In the matter of Aquila, Inc.	)	
d/b/a Aquila Networks ("Aquila")	)	Docket No. NG-
seeking a general rate increase	)	Docket No. NG-
for Aquila's Rate Areas One, Two	)	Docket No. NG-
and Three (not consolidated)	)	

Direct Testimony of Vern J. Siemek

Senior Manager- Financial Management, Nebraska Operations

Limited Cost Recovery

Offutt Housing Adjustments

OPPD Reversion Adjustment

Insurance Adjustment

November, 2006

Vern J. Siemek
1815 Capitol Avenue
Omaha, NE 68102
402-221-1705

Q. Please state your name and business address.

A. My name is Vern J. Siemek. My business address is Aquila, Inc., 1815 Capitol Avenue, Omaha, Nebraska, 68102-4914.

Q. By whom are you employed and in what capacity?

A. I am currently employed by Aquila, Inc. ("Aquila" or "Company") as Senior Manager - Financial Management for Aquila's Nebraska Networks business unit.

Q. What are your current responsibilities?

A. I am responsible for budgeting, reporting, and financial analysis relating to Aquila's Nebraska Networks business unit. I have held this position since 2002.

Q. Briefly describe your educational background and employment history.

A. I earned a Bachelor of Science degree in Business Administration with Distinction from the University of Nebraska at Lincoln in 1973 and am now a Certified Public Accountant in Nebraska.

From 1994 to 2002, I held the positions of Director and Senior Director of Business Services in Kansas City, Missouri for the utility network of Aquila in the United States. My responsibilities included financial analysis and support of Aquila's utility network.

From 1987 to 1994, I held the position of Manager of Business Development in Omaha, Nebraska, for Peoples Natural Gas ("Peoples"). Peoples was an Aquila division with gas operations in Colorado, Iowa, Kansas, Nebraska and Minnesota.

From 1984 to 1987, I was in charge of the Regulatory Affairs group for Peoples.

Before joining Peoples, I was employed for eleven years in the Regulated Industries division of an international accounting firm in various capacities, including five years as an audit manager. As part of my responsibilities, I supervised the audits of regulated companies and the reviews of annual reports to the Federal Energy Regulatory Commission.

Q. Have you ever testified before regulatory commissions?

A. Yes. I have submitted testimony and, in most cases actually testified before, the Nebraska Public Service Commission, the Kansas Corporation Commission, the Iowa Utilities Board, the Missouri Public Service Commission, the Arkansas Public Service Commission, and the Oklahoma Corporation Commission.

Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

A. My testimony will explain and support the following proposed adjustments:

1) **Limited Cost Recovery:** Support Aquila's Limited Cost Recovery mechanism ("LCR"). The LCR provides for annual, minimal revenue increases that reduce the need for larger, periodic rate increases while avoiding the significant cost of pursuing annual General Rate Cases.

2) **Offutt Housing**: Support 'normalization' of the expected level of capital investment and operations for the rehabilitation, demolition, and abandonment of Offutt Air Force Base housing units. Adjustment # 2

3) **OPPD Reversion:** Support the ending of allocations of corporate and local support costs to the unregulated OPPD meter reading contract when that contract is terminated on March 31, 2007. Adjustment # 12

4) **Insurance:** Support the adjustment to reflect current levels of insurance costs, normal levels of self-insurance provisions, and expected future insurance savings. Adjustment # 19

LIMITED COST RECOVERY ("LCR")

Q. What is the LCR?

A. The LCR changes rates annually to reflect the normal annual increases in costs to serve gas customers. The annual increase in rates is based on increasing operating costs approved within a General Rate Case using the Consumer Price Index-Urban.

Q. What are the advantages of an LCR?

A. The LCR provides for annual, minimal revenue increases that reduce the need for larger, periodic rate increases. The LCR mechanism also avoids the significant cost of pursuing annual General Rate Cases, which is the only available alternative to ensure that costs of serving customers are appropriately reflected in rates. Annual General Rate Cases are not cost-efficient regulation for customers.

Q. How is an LCR annual increase implemented?

A. In Docket No. NG-0031, the Nebraska Public Service Commission denied a request by Aquila for an LCR. Among other reasons, the request was denied because it "…must be handled through the procedures set forth in § 66-1838." (i.e. the request needed to be handled within the procedures for a general rate filing). However, in its Order denying Aquila's LCR application, the Commission stated that "Jurisdictional utilities are encouraged to continue to present rate proposals that minimize regulatory costs and increase efficiency. Such proposals must fit within the parameters of § 66-1808. The Commission is open to considering such requests." *In the Order of Aquila, Inc. Seeking Limited Cost Recovery In Nebraska,* Docket No. NG -0031, Order Issued November 1, 2005.

To address the Commission's finding about implementing a limited cost recovery mechanism within a general rate filing, this LCR mechanism and its parameters and processes are requested within a General Rate case and conform to the statutory requirements of the State Natural Gas Regulation Act.

In other words, the Commission will first review Aquila's general rate filing, investigate all of Aquila's revenues and costs, and approve a general rate increase as is usually done. However, in addition to reviewing and approving the rates, the Commission will also establish and approve an LCR mechanism with parameters, processes and rate design decisions that will be implemented to recover costs on a limited basis in succeeding years. The LCR proposed in this case is similar in concept, but not identical to the one proposed by Aquila in Docket No. NG–0031. Modifications were made to more closely follow the precedent offered by the California Attrition Adjustment, as well as incorporating the LCR into a General Rate Case filing.

Q. What are the specific findings needed by the Commission to implement an LCR?

A. The LCR parameters to be set by the Commission as part of this rate case include establishing the annual CPI-U change for the future LCR increases, and establishing a cap for the percentage increases that is based on the CPI-U.

The LCR process also determines what categories of costs may be included in the future base costs for the annual increase. The process also specifies that the increases are implemented only after Aquila files an annual LCR Notice Letter shortly before the end of the fiscal year. The LCR Notice Letter notifies the Commission of the planned increase effective January 1 of the following year. The Notice Letter percentages are based on the most recent CPI-U information, but are capped by the estimated CPI-U factor approved in the General Rate Case. The LCR process could be terminated, after notice and further hearing by either the Commission or Aquila if the LCR is no longer appropriate or reasonable.

Q. Is there any regulatory precedent for such a mechanism?

A. Yes. A very similar mechanism has been used extensively by the California Public Utilities Commission since the early 1980's to recognize the same annual cost increases that the LCR addresses. That mechanism is called an Attrition Rate Adjustment mechanism ("ARA") since it compensates for the attrition in allowed earnings suffered by utilities in the interim years between general rate cases. The California ARA has been used for over twenty years by major electric and gas companies in California, and was recently expanded to include water utilities. It has been modified over the years but generally uses specific projected indices for particular elements of cost, including payroll, non-payroll and plant.

The process was originally developed so that rate cases by the major utilities could be staggered to manage the California Commission's workload. The ARA gave utilities the ability to operate for several years between General Rate Cases.

Exhibit ____ (VJS-1), attached to this testimony, lists citations to relevant cases authorizing an ARA in California.

Q. Are there any similar precedents in Nebraska?

A. Yes. Nebraska Revised Statute § 86-148 provides the Telecommunications Statutory Standard. That statute allows telecommunication companies in Nebraska to increase rates if the cost recovery is less than 1% of revenues of the telecommunication company. Neb. Rev. Stat. § 86-148. This permitted cost recovery is a form of limited cost recovery recognized by Nebraska.

The Commission has also established its own rules and regulations for limited cost recovery in Nebraska. For example, Chapter 5 of the Commission's Rules and Regulations sets forth the regulations applied to telecommunication companies. Rules and Regulation 002.29A5 provides as follows:

> Telecommunications Rules and Regulations:
>
> 002.29 application for new Rates or charges, or Changes in existing Rates or Charges for Telephone Services: 002.29A5. <u>This rule shall not apply to rate increase of utilities if such rate increase are</u>: …or …002.29A5b. <u>Which do not increase the utility's aggregate annual revenue by more than one percent</u>. Neb. Admin. Code, Title 291, Ch.5, 002.29A5b.

Implementation of LCR

Q. How would Aquila recommend implementing the LCR mechanism in Nebraska?

A. The Commission's order in this case is expected to increase Aquila's existing rates to a level of cost recovery that represent 2007 costs, after reflecting known and measurable changes in costs. These costs serve as the starting point for the LCR.

In addition to new rates reflecting 2007 costs, the Commission's order for the current rate case would also permit the following:

1) Authorize Aquila to file an LCR Notice Letter by October 1 of each succeeding year (until revoked) for new rates effective on the following January 1.

2) Set the parameters for LCR increases. Aquila proposes using the latest annual change in CPI-U as the LCR increase factor. CPI-U increases since 1981 are included on Exhibit _______(VJS-2) for review. The CPI-U represents the latest available historical cost increase data used to approximate the cost increases in the first succeeding LCR year. A cap on allowable CPI-U factors would also be set in the order to prevent one-time spikes in costs from creating large one-year rate increases. Aquila proposes that the cap for LCR factors be set 50% higher than the average CPI-U increases for the preceding four years (2.9%). The cap would add 1.4% and sets the maximum increase at 4.3% of subject cost elements for the maximum allowable LCR increase in each year. During the last 25 years, 4.3% would have capped the increase 5 times or 20%.

3) Set the cost elements to be subject to the CPI-U multiplier. Aquila proposes that the LCR increase factor be applied to the total of the approved levels of operations and maintenance expense, depreciation, and taxes other than income taxes.

Operations and maintenance expense is included as a cost element since it is most directly impacted by normal annual increases. Taxes other than income taxes are included as a cost element because payroll taxes are a major element that is directly impacted by annual labor increases. Depreciation is included as a cost element as a reasonable surrogate for the annual increases in depreciation on annual capital investments. Gas costs are handled separately through processes already in place.

4) Set the rate design for the increase. Aquila proposes that the increase be added to the Customer Charge for all residential and commercial sales and transport customers. Increasing the Customer Charge will ensure that the customer efficiencies in gas usage do not add additional pressure for a General Rate Case.

LCR Example

Q. Please describe how the recovery mechanism under Aquila's LCR would actually work.

A. The mechanism can be illustrated as follows:

1) The LCR annual factor (subject to the LCR cap) would be the latest available annual CPI-U increase. It assumes, for illustrative purposes only, that the August 2007 CPI factor is 210.0. The August, 2006 CPI-U factor is 203.9 (measured against a 1982-1984 base). Thus, the LCR annual factor for 2007 would be calculated as 3% ((210.0/203.9) -1).

2) That 3.0% would be applied to the total of operations and maintenance expense, depreciation, and taxes other than income taxes approved in the General Rate Case. Again, for illustrative purposes, assume that those approved costs are $50,000,000.

3) The Notice Letter dated October 1, 2007 would calculate the LCR increase to be $1,500,000 (3% times $50,000,000) to be effective January 1, 2008. The LCR would be divided by the most recent annual average residential and commercial customer count. The added monthly customer charge for residential and commercial customers would be one-twelfth of that amount. Assuming 190,000 Residential and Commercial customers in 2006, the increase in the monthly customer charge for each of Aquila's customers under its LCR would be $.66, effective Jan 1, 2008.

4) Subsequent Notice Letters would reflect the increased margin including the prior LCRs. Assuming the same CPI-U increase of 3% for the next year, the LCR for 2009 would become $1,545,000 ($51,500,000 times 3%). That LCR increase for the updated 192,000 average customers for Aquila would increase the monthly customer charge for 2009 by $.67 effective Jan 1, 2009. The total cumulative LCR for 2009 would be the 2008 amount of $.66 and the 2009 amount of $.67 for a total of $1.33 per month. These annual increases would continue until either the Commission or Aquila determined that the LCR increases were no longer appropriate.

5) In subsequent General Rate Cases, any changes in general rates would be net of the LCR increases already granted, thereby reducing the size of a general rate filing that would otherwise be required.

The Benefits of the LCR

Q. What are the benefits of the LCR?

A. There are several benefits to the LCR:

1) The LCR saves customers the substantial costs ($500,000 to $700,000) of pursuing annual General Rate Cases that may otherwise be conducted.

2) The LCR better reflects the typical annual increases in costs and investments to serve customers that should, in equity, be paid by those customers being served.

3) The LCR is intended to replace larger rate increases every three to four years with smaller, annual increases that more nearly track costs as well as being easier to afford.

4) The LCR may extend the larger filings if LCR increases reasonably track costs.

5) The LCR in general eliminates the need to consider in a General Rate Case “known and measurable” changes that extend beyond the first year of a general rate increase.

Q. What are the expected costs of pursuing an annual General Rate Case?

A. Aquila costs include class cost of service studies, cost of capital studies, legal counsel, and depreciation studies, as well as other costs.

The Public Advocate costs include legal counsel's costs for pleadings, discussions, and hearings. Those costs also included retaining consultants for reviewing the accounting records and positions of Aquila, as well as developing testimony for the hearings.

Commission advisors include consultant costs for advising the commission on the various issues in dispute between Aquila and the Public Advocate.

These costs for preparing and investigating the costs of a general rate case do not include internal Aquila resources. Nor do these costs include the commission's internal resources, which are funded by general assessment.

Q. How much are the costs of pursuing an annual General Rate Case?

A. In the General Rate Case filed in 2003, Aquila incurred about $214,000, and the Public Advocate and commission consultants totaled another $98,000. These costs would have been higher had costs for hearings and legal briefings been incurred. Those hearing and legal counsel were avoided since the parties were able to negotiate a settlement eliminating hearings and legal briefs. The negotiated settlement likely saved customers another $100,000 to $200,000 in rate case costs.

Aquila estimates its costs in this case will be $500,000, reflecting testimony of expert witnesses, general investigation, hearing costs and legal counsel support. The Public Advocate and commission consultant could total $200,000 to conduct its review, prepare testimony, conduct hearings and provide legal support.

Q. Who pays for those costs?

A. General regulatory principles provide for recovery of these legitimate costs in rates as these costs represent a necessary part of the cost of regulation. The Aquila portion is generally amortized over the period the new rates are expected to be in place. The costs for the Public Advocate and the commission consultants are charged to customers as a surcharge after the case is finalized.

That same level of costs would be incurred <u>annually</u> if General Rate Cases were filed annually.

Q. Why doesn't Aquila just file annual General Rate Cases instead of proposing the LCR?

A. Aquila in the past has chosen to forego annual general rate cases in part because the costs to pursue General Rate Cases are so great compared to the annual cost increases being borne by Aquila. The amount of the typical annual rate increases needed (about $2 million) was small compared to the cost to our customers of annual rate cases. With annual General Rate

Cases, our customers would be burdened with an additional $500,000 to $700,000 annually in rate case costs, to produce roughly $2 million of annual rate increases.

Historically, Aquila has chosen to forego earning its statutory allowed rate of return until the gap in earnings is distressing enough to file a General Rate Case to reflect those costs to our customers while incurring the costs to pursue a General Rate Case.

However, foregoing General Rate Cases is inequitable to Aquila and its investors and such self-imposed shortfalls can not be projected into the future.

Although annual General Rate Cases filed pursuant to the State Natural Gas Regulation Act in Nebraska would be equitable to Aquila to ensure that margins fairly recover costs, it could be costly to our customers because of the significant costs to pursue a General Rate Case. In addition to external costs, accommodating annual rate cases would likely require additional internal staff additions for both Aquila and the Commission, increasing costs even further. The LCR minimizes costs with an effective and efficient alternative to the cost of annual General Rate Cases.

Q. Please illustrate why Aquila's costs increase annually.

A. Aquila's costs increase annually for a number of factors. Those cost increases result in lower earnings and a failure to recover the costs to serve our customers. Exhibit ____ (VJS-3) illustrates the typical pattern for cost increases that totals over $1.65 million.

Q. Why do you expect capital investments to continue to exceed depreciation?

A. Long term capital projections indicate continued needs for infrastructure to support long-term growth and to provide support for past growth.

Q. What makes you conclude that customers prefer smaller annual increases compared to larger triennial increases?

A. Simple logic tells us that most customers would be better able to accommodate smaller annual cost increases in their personal budgets. An increase of $1 per month translates to about 1% of gas bills on an annual basis. The triennial rate cases have typically resulted in much larger increases.

In addition, in our discussions over many years with city officials, we have heard repeatedly that smaller, more frequent, increases are much more preferable to customers than the larger multiyear increases. As noted above, the Commission itself directed Jurisdictional Utilities in PSC Docket No. NG-0031 to look for ways to minimize regulatory costs and increase efficiency.

Q. How would the LCR annual increases reduce the larger periodic increases?

A. The annual LCR increases would reduce the size of costs not being charged currently in rates. By reducing the gap in rates and costs, it is expected the General Rate Cases will be less frequent than in the past. The General Rate Case increases would definitely be smaller than without the LCR increases because the LCR increases would be reflected in the base and test year revenues.

Q. Can you illustrate this effect?

A. Yes. Assuming that annual cost increases are $1.65 million with no LCR. After three years, the shortfall in rates is $4.95 million. That shortfall equates to earning about 4% less than the allowed equity rate of return, which is almost half of the allowed equity return. This significant shortfall creates the need to file a General Rate Case for $4.95 million, and that case would also include known and measurable changes to update the test period. With an LCR increase, the same increases of $1.65 million would be reduced by the LCR increase of $1.5 million, netting a deficiency of only $.15 million per year. It would take many years of that deficiency or significant other cost increases to reach the level of the $4.95 million shortfall. After three years of LCR increases, a General Rate Case would be for less than $.45 million, absent any other cost increases.

Q. What are some examples of "known and measurable" adjustments that no longer need to be considered if an LCR is approved?

A. One example is union wage increases. In this filing, there are proposed adjustments for union contractual and non-union merit increases for 2007. Those same adjustments could have been included as "known and measurable" for 2008. The LCR eliminates the need to include those costs in this filing. With the LCR, those cost increases is 2008 will be appropriately reflected in 2008 costs without necessitating an expensive General Rate Case.

Another example is multiple-year construction commitments such as Aquila's Copper Settlement Loop/Bare Service Line replacement program. The CSL project is a commitment to invest approximately $1.15 million annually for ten years. On the basis of Aquila's commitment and the 2-year history of investing at that level, the entire remaining eight years commitment of $9.2 million could have been proposed for inclusion in rate base and depreciation. The LCR mechanism eliminates the need to reflect those future years of planned investment in this case.

Q. Can Aquila guarantee that General Rate Cases would be less frequent than current experience?

A. No. There are infrequent cost experiences that are so significant and atypical that it is not possible. Examples might include increases in pension costs due to investment results, new accounting rules, major capital investments, and significant medical cost increases. However, adopting an LCR would reduce the impact of these changes and would still be expected to increase the time between General Rate Cases.

Q. How does the Commission ensure that Aquila does not earn significantly more than a fair rate of return?

A. The regulatory framework in Nebraska, as well as historical context, provides the Commission oversight and information to guard against excessive returns:

1) Aquila reports its results of operations annually to the Commission. That information can be used by the Commission to determine whether Aquila's earnings appear excessive. Under the Act, the Commission always has the right to conduct an earnings investigation.

2) The Commission also can look to the historical pattern of Aquila rate cases for additional assurance. Exhibit _____ (VJS-4) calculates the average annual rate increase approved to be over $1.8 million, compared to the $1.5 million of LCR increase in the illustrative calculation.

3) Another check on over-earning calculates the likely results of a 2004 General Rate Case assuming all issues were resolved per the 2003 negotiations. Exhibit _____ (VJS-5) illustrates the result of a General Rate Case using 2004 results as the test period. That increase would have been $1,690,717. That compares to the illustrative LCR increase of $1.5 million in this case.

Each of these approaches provides protection and assurance for the customer and the Commission that Aquila will not earn more than a fair return on investment.

Finally, it should be noted that in addition to the requirements of the Act, Aquila management will commit to forego an LCR if results of operations do not support an increase and do not justify an increase. Since any filing decision would be readily reviewed by subsequent annual reports, the Commission could take action to terminate future LCR increases. Aquila's objective is not to exceed allowed returns, but to be able to actually earn them as the costs to serve our customers increase each year.

Q. Does the LCR presume approval of other Aquila proposals such as the Revenue Normalization Adjustment?

A. Yes. If the RNA is not approved, conservation by customers should be addressed within the LCR by substituting total allowed margins as the cost element subject to the CPI-U. That change then allows conservation and its loss of margins to be included in the LCR.

Offutt Normalization

Q. What is the Offutt Air Force ("Offutt") base housing project?

A. Prior to 2005, Offutt owned and operated the distribution system within its housing divisions, serving 2,591 residential units. Aquila served Offutt as a large volume customer, but had no responsibilities for the distribution system or individual customers. In late 2005, Offutt privatized its housing units to a group lead by Omaha-based America First to economically modernize and rehabilitate the housing. The plan for privatization included a comprehensive plan of demolition, abandonment, renovation and rebuilding to yield 1,631 modernized units by 2011.

Q. How did the privatization impact Aquila?

A. As the existing gas distributor in the Bellevue area, Aquila acquired the existing gas distribution network. That acquisition included an obligation to make capital investments (at an estimated cost of $1,094, 690) to the gas network to support the modernized units. These investments include meters for all units and servicelines for relocated units over the term of the renovation. Aquila also added all the normal, ongoing responsibility for safely operating a distribution system.

Q. Why does this acquisition create adjustments to Aquila investments and operating costs in this filing?

A. There are several investment and cost areas requiring adjustment. The overall basis for the adjustments is to properly reflect and match margins, costs and investments included in the test period to the margins, costs and investments after the project is completed. Full margins have been billed to America First since the acquisition and are included in the test period, but many of the related costs have not been reflected or were only partially reflected. By cost area, the necessary adjustments are:

1) **Capital:** Investment has just begun as of June 30, 2006 so the investment is not yet reflected in the rate base. For efficiency, Aquila's investment will be synchronized with the overall rehabilitation plan as units are built or refurbished. As a result, the costs in the test period have virtually none of the investment that is needed to support the margins that are in the test period. The adjustment reflects the expected level of investment to support the Offutt network when complete.
2) **Depreciation**: The capital adjustment would generate depreciation expense to support the Offutt network.
3) **Operating costs**: Fully allocated operating expense was incurred only for the 8.5 months of the acquisition. Normalizing the operating expense to reflect the final number of customers would increase operating costs to reflect a full year costs for 1,631 customers.
4) **Margins:** Margins in the test period reflect the higher number of customer premises that are being demolished, as well as usage for only 8.5 months since November 15, 2005. Adjusting to the ultimate level of units and for twelve months usage creates an adjustment to properly reflect the expected future level of margins.

Q. Why is the expected future level the proper basis for setting rates in this filing?

A. Clearly it would not be appropriate to leave over $400,000 of margins in the test period without reflecting the related investment and operating costs that create those margins. A normal new customer situation would have both the supporting investment and much of the operating costs reflected at the same time as the new margins are reflected. To fail to reflect the similar Offutt investments and costs would significantly overstate the margins and understate the costs of providing service to the Offutt housing units.

In addition, the margins in the test period are significantly overstated because almost 1,000 units in the original acquisition will end up being demolished and their margins eliminated.

The expected future level of units and costs are known and measurable and can be used to adjust this overstatement in the test period.

OPPD Reversion

Q. What is the OPPD meter reading contract?

A. Aquila has a contract with Omaha Public Power District to read the electric meters for approximately 85,000 OPPD customers primarily outside the city limits of Omaha. The contract allowed some joint reading of electric and gas meters at a lower cost to OPPD and to Aquila. The direct Aquila costs for reading electric meters were segregated under the Aquila accounting system so that costs were properly paid by OPPD. Corporate and Nebraska governance and management costs were also allocated to the OPPD contract under Aquila's allocation process, so those costs also were paid by OPPD.

Q. Has the contract changed?

A. Yes, OPPD announced earlier this year that OPPD is investing in an Automated Meter Reading system similar to the one Aquila employs in Lincoln. As a result of that investment, OPPD notified Aquila that the meter reading contract would be terminated effective March 31, 2007.

Q. Can Aquila have OPPD read its joint meters by using automated meter reading system?

A. No. The automated meter reading is connected only to OPPD's electric meters. Aquila must still read its own natural gas meters at those customer locations even though it will no longer be reading OPPD's electric meters.

Q. What is the impact of Aquila direct costs to gas customers?

A. Aquila is planning to eliminate any impact to direct costs by managing the staff changes created by the cancellation of the contract. Aquila expects to reduce related costs (about 10 positions) by the approximate charges to the OPPD contract. Aquila's plan should result in no change to the direct costs to serve gas customers.

Q. Is there any other impact to gas customers from the cancellation?

A. Yes. It is not possible to similarly reduce the allocated supervisory costs that were allocated to the OPPD contract. These costs involve small percentages of management and supervisory costs that were not readily identifiable as OPPD. These costs were allocated to the OPPD contract to fully allocate such costs to all operations. Aquila's Nebraska customers have benefited in the past from the allocation of such governance costs to the OPPD contract.

Q. What is the approximate impact of the reversion of allocated costs?

A. The total costs allocated for the twelve months ended June 30, 2006 were $349,416. After allocating an appropriate portion of that cost to ServiceGuard ($18,868), the balance remaining for gas operations is $330,548.

Q. What is the proper treatment of those costs formerly allocated to the OPPD contract?

A. Without the OPPD contract, the allocated costs can no longer be charged to OPPD. Instead, those costs will primarily revert, and should be reflected in, the remaining existing Nebraska operations of Aquila. Those Aquila operations are gas services and ServiceGuard. The proposed pro forma entry reflects the utility portion's impact of the reversion of those costs to utility operations.

INSURANCE

Q. What is the insurance adjustment proposed by Aquila?

A. The insurance adjustment has several elements. First, it annualizes current insurance costs during 2006, which are based on premiums paid earlier in 2006. Second, it also normalizes costs for self-insured losses based on the average of the most recent three years claims experience. Lastly, it projects decreases in insurance costs based on anticipated reductions of 2007 premiums based on industry trends.

RECOMMENDATIONS

Q. What are your recommendations?

A. My recommendations are:

1) That the Commission approve the LCR as proposed by Aquila.

2) That the commission approve the Offutt, OPPD and Insurance proforma adjustments as proposed by Aquila to properly state costs and revenues for the test period.

Attachments:

____VJS-1 Copy of selected portions of California filings and rulemakings dealing with Attrition Adjustment

____VJS-2 Historical Consumer Price Index- Urban dated June 2006. (From US Dept of Labor website http://data.bls.gov/cgi-bin/surveymost **)**

____VJS-3 Illustration of typical pattern of annual cost increases

____VJS-4 Annual Nebraska rate increases approved

____VJS-5 Illustrative calculation of 2004 General Rate Case

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit _____ (VJS-1)

California Filings with Attrition Adjustments

Pacific Gas & Electric Decision 93887, Application 60153, Issued December 30, 1981 "… current NOI procedure … where utilities apply for a general rate increase every two years with an attrition adjustment made in the year following the test year" "PG&E is authorize to file an advice letter requesting additional revenues to offset operations and financial attrition in 1983 for its gas operation calculation in accordance with our adopted ARA "attrition Rate Allowance" mechanism and is authorize to file revised gas rates reflecting this allowance to become effective January 1, 1983." This decision allowed one Attrition Year/allowance after the general rate case.

Southern California Edison Decision NO. 82-12-054 issued Dec 8, 1982 Authorizing a General Rate increase and setting terms for an additional increase in 1984. "an allowance for operation and financial attrition is necessary for SoCal to offset increased cost in the second year during which the new rates will remain in effect. Providing a step-rate increase effective January 1, 1984 is a reasonable means to properly reflect these increase in cost."

Pacific Gas and Electric, Southern California Edison, Southern California Gas, Pacific Lighting Gas Supply, San Diego Gas & Electric - Decision 85-12-076, issued December 18, 1985 This decision extended Attrition Year to the second year following the General Rate Case and set terms for each of the companies.

Southern California Gas and Pacific Lighting Gas Supply Decision No. 87-05-027 Issued May 13, 1987 Approving stipulation and agreement "In lieu of a general rate case for test year 1988, SoCal will make attrition filing for 1988 and 1989."

Pacific Gas & Electric Decision No. 00-02-046 issued February 17, 2000 –"we will grant an attrition adjustment for Attrition Year 2001"

California Public Utilities Commission Evaluate Existing Practices and Policies for Processing General Rate Cases R.03-09-005, Decision 04-06-018 Issued June 9, 2004 Rulemaking relative to Class A water utilities with over 10,000 service connections. "Second, we adopt a simplified, inflation-based escalation methodology for two years of the three-year cycle."

Southwest Gas Corporation Decision 04-03-034, A.02-02-012 issued March 16, 2004 "Commission provides for attrition increases in both divisions in 2004, 2005, and 2006." 232 PUR4th 353

Pacific Gas & Electric Decision 04-05-055 issued May 27, 2004 " The attrition mechanism originated in SoCalGas 1981 GENERAL RATE CASE…An attrition adjustment for PG&E was first adopted in PG&E's TY 1982 GENERAL RATE CASE. In that decision, the Commission found that "an attrition mechanism is a necessity in this period, where the economy is unpredictable and volatile. We believe the adoption of indexing under these circumstances is a necessity to assure that PG&E will be able to recover its cost and also to protect ratepayers from possible overestimate of expenses.""

" In D.85-12-076, the Commission reconsidered the attrition mechanism and declined to eliminate it at that time…[because] a three year rate case cycle with but one year of rate relief would not give the utilities a reasonable opportunity to earn their authorized rate of return." "The Commission has since approved attrition adjustment in four of PG&E's GENERAL RATE CASEs (D.86-12-095, D.89-12-057, D.92-12-057, and D.00-02-046)

Pacific Gas & Electric Docket No. A0512002 filed December 2, 2005
General Rate Increase for 2007 - $114 million (updated to $44 million)
Attrition rate increase for 2008 - $186 million (updated to $143 million)
Attrition rate increase for 2009 - $242 million (updated to $141 million)

Exhibit ____ (VJS-2)

Historical Consumer Price Index – Urban

(Base years 1981-1984)

	Dec. Index	Dec to Dec Increase
1981	94.0	8.9%
1982	97.6	3.8%
1983	101.3	3.8%
1984	105.3	3.9%
1985	109.3	3.8%
1986	110.5	1.1%
1987	115.4	4.4%
1988	120.5	4.4%
1989	126.1	4.6%
1990	133.8	6.1%
1991	137.9	3.1%
1992	141.9	2.9%
1993	145.8	2.7%
1994	149.7	2.7%
1995	153.5	2.5%
1996	158.6	3.3%
1997	161.3	1.7%
1998	163.9	1.6%
1999	168.3	2.7%
2000	174.0	3.4%
2001	176.7	1.6%
2002	180.9	2.4%
2003	184.3	1.9%
2004	190.3	3.3%
2005	196.8	3.4%

Exhibit _____ (VJS-3)

Illustration of Typical Pattern of Annual Cost Increases

1. Operations expense – that increase can be roughly approximated (and is caused by) inflationary pressures. Wage increases, increases in fuel costs, and increases in materials costs and supplies all generally increase similar to the inflation experienced by the US economy in general. Wages are the largest single component of Aquila's costs and wages in the US in general approximate the increase in the Consumer Price Index – Urban. With over $30 million of operating costs, a 3% cost increase is at least: **$900,000**

2. Capital investments to serve customers and keep existing system safe – those investments substantially exceed the level of depreciation expense allowed in rates. This excess over depreciation increases Aquila's net plant investment and thus Aquila's rate base grows. A capital budget of $12 million annually would increase rate base by roughly $4 million ($12 million capex less depreciation expense of about $8 million). Return on that increased rate base is not earned until a General Rate Case: **$400,000**

3. Depreciation impact of the capital investment in 2 above since depreciation expense increases as gross plant increases. Capital spending of $12 million would increase annual depreciation expense by a minimum of **<u>$350,000</u>**

4. These individual cost patterns add up to an annual 'Attrition' of: **$1,650,000**

In addition, other expenses typically create exposure to annual cost increases as they tend to increase costs at higher than CPI-U increases. Those costs include health care, retiree medical benefits, and pensions.

Exhibit ____ (VJS-4)

Annual Nebraska Rate Increases Approved

				Approved/Negotiated	Test Year
	Rate Actions (1992)				
1		Minnegasco	$	2,749,441	1991
2		Rate Area 3	$	995,000	1991
3		Rate Area 2	$	31,082	1991
	Rate actions (1995-1996):				
4		Rate Area 1	$	780,000	1994
5		Rate Area 2	$	3,500,000	1995
6		Rate Area 3	$	2,000,000	1995
	Rate Actions (1999)				
7		Rate Area 2	$	1,850,000	1998
8		Rate Area 3	$	1,750,000	1998
	Rate Actions (2003)				
9		All Rate Areas	$	6,172,000	2002
10	Total increases approved/Negotiated		$	19,827,523	
11	**Number of years of** increases			11	
12	**Average Annual Increase**		**$**	**1,802,502**	

Exhibit ____ (VJS-5)

Illustrative Calculation of 2004 General Rate Increase

1.	Test Year Costs from General Rate Case (Operations, Maintenance, Depreciation)		$34,306,083
2.	Actual Costs from 2004	$36,803,222	
3.	Jurisdictional Portion of 2004 costs		$34,536,489
4.	Proformas reflected in 2003 negotiations for cost-setting:		
	A. Variable compensation	($339,292)	
	B. Marketing	($25,573)	
	C. Lobbying (excluded from 2004 costs)	-	
	D. Donations (excluded from 2004 costs)	-	
	E. Memberships	($146,334)	
	F. Amortization of 2002 reorganization costs	$563,757	
	G. Payroll increases 1/1/5 union and 3/1/5 nonunion	$352,518	
	H. Annualized depreciation	$970,418	
	I. Annualized depr on 2005 Integrity Capital Budget	$180,662	
	Total Proforma adjustment	$1,556,156	
	Jurisdictional proformas		$1,460,311
5.	Jurisdictional costs 2004 test period with proformas		$35,996,800
6.	Justifiable rate increase excluding rate base increases		$1,690,717

Note: This alternative method of determining an equitable increase is based on the results of the 2003 General Rate Case that was litigated and negotiated. Proforma adjustments of Aquila that were accepted were reflected, as were any Staff or Public Advocate adjustments proposed during the case. These adjustments were reflected solely for the purpose of determining an increase expected to be approved without substantial dispute. These calculation are for illustrative purposes only and do not constitute admission against intent, are not binding on either party in future proceedings and position or representations may be offered in any subsequent rate filing.

BEFORE THE

NEBRASKA PUBLIC SERVICE COMMISSION

Docket No. __________

Aquila Inc.

(d/b/a Aquila Networks)

Prepared Direct Testimony of

Thomas J. Sullivan

Issues:

Revenue Synchronization Adjustment
Class Cost of Service
Rate Design

November, 2006

Q. Please state your name and business address.

A. Thomas J. Sullivan, 11401 Lamar, Overland Park, Kansas 66211.

Q. What is your occupation?

A. I am a Vice President of Black & Veatch Corporation. I am currently assigned to the Company's Enterprise Management Solutions Division where I serve as the Leader of the Financial Advisory Services group.

Q. How long have you been associated with Black & Veatch?

A. I have been employed by the Company since 1980.

Q. What is your educational background?

A. I earned a Bachelor of Science Degree in Civil Engineering from the University of Missouri - Rolla in 1980, summa cum laude, and a Master of Business Administration degree from the University of Missouri - Kansas City in 1985.

Q. Are you a registered professional engineer?

A. Yes, I am a registered Professional Engineer in the State of Missouri.

Q. To what professional organizations do you belong?

A. I am a member of the American Society of Civil Engineers.

Q. What is your professional experience?

A. I have been responsible for the preparation and presentation of numerous studies for gas, electric, water, and wastewater utilities. Clients served include investor owned utilities, publicly owned utilities, and their customers. Studies involve valuation and depreciation, cost of service, cost allocation, rate design, cost of capital, supply analysis, load forecasting, economic and financial feasibility, cost recovery mechanisms, and other engineering and economic matters.

Prior to joining the Enterprise Management Solutions Division in 1982, I worked as a staff engineer in the Company's Energy and Water Divisions.

Q. Have you previously appeared as an expert witness?

A. Yes, I have. In Exhibit__ (TJS-1), I list cases where I have filed expert witness testimony.

Q. Have you previously filed testimony before the Nebraska Public Service Commission?

A. Yes, I have. I filed testimony in Aquila's last rate case filed before the Commission. I sponsored the weather normalization adjustment in that case. In addition, I have testimony filed before the Commission in connection with Kinder Morgan's current rate case. In that case, I provide testimony on the weather normalization adjustment, the test year billing determinants, revenues under existing rates, customer and usage trends, and rate design.

Q. For whom are you testifying in this proceeding?

A. I am testifying on behalf of Aquila, Inc. ("Aquila" or "Company").

Q. What is the nature of your responsibilities in this engagement?

A. The Company asked me to:

1. Prepare the Company's proposed revenue synchronization adjustment.
2. Allocate costs between the Company's four rate areas.

3. Prepare a jurisdictional class cost of service study based on the Company's proposed test year jurisdictional revenue requirement.
4. Based on the methodology traditionally used by the Company to design rates, design jurisdictional rates which will produce revenues equal to the Company's proposed test year jurisdictional revenue requirement.
5. Develop alternative rate designs and compare those rates to the rates I propose. Specifically, I develop alternative rates using (1) the traditional rate design structure with all of the proposed revenue increase being collected through increasing the existing customer charges and (2) rates based on a flat charge per month.

After this initial introductory section, my direct testimony is divided into sections that parallel these responsibilities.

Q. Do you sponsor any exhibits?

A. Yes, in addition to Exhibit__(TJS-1) previously discussed, I sponsor the following exhibits:

Exhibit___(TJS-2) - Jurisdictional Revenue Synchronization Adjustment (Revenues Under Existing Rates)

Exhibit___(TJS-3) – Jurisdictional Class Cost of Service Allocation – Rate Area 1

Exhibit___(TJS-4) – Jurisdictional Class Cost of Service Allocation – Rate Area 2

Exhibit___(TJS-5) – Jurisdictional Class Cost of Service Allocation – Rate Area 3

Exhibit___(TJS-6)- Proposed Rates - Jurisdictional Rate Areas

Exhibit___(TJS-7) - Revenues Under Current and Proposed Rates – Rate Areas 1, 2, and 3

Exhibit___(TJS-8) – Alternative Rates – Increase Customer Charge Only

Exhibit___(TJS-9) – Alternative Rates – Flat Charge Approach

Exhibit___(TJS-10) – Typical Bills Under Existing, Proposed, and Alternative Rate Designs

Q. In your testimony, you refer to jurisdictional and non-jurisdictional customers. Please explain.

A. I define jurisdictional customers as Residential, Commercial, and Energy Options Firm customers. These customers are regulated by the Commission. I define non-jurisdictional customers as High-Volume and/or Complaint-based customers. The High-Volume customers are not subject to the direct jurisdiction of the Commission and the Company is not proposing any changes to the rates or services for the Complaint-based customers.

The Nebraska State Natural Gas Regulation Act ("Act") defines a High-Volume customer as a high-volume rate payer whose natural gas requirements equal or exceed 500 therms per day as determined by their average daily consumption (approximately 180,000 therms per year). These High-Volume customers comprise the Company's non-jurisdictional Rate Area 4 in its entirety.

A Complaint-based customer is defined as agricultural or interruptible customers not otherwise qualifying as High-Volume customers. These customers are included in the Company's Rate Areas 1, 2, and 3 along with the Company's jurisdictional Residential, Commercial, and Energy Options Firm customers.

The Company also refers to Rate Area 1 as the Metro (Omaha) service territory, Rate Area 2 as the Lincoln service territory, and Rate Area 3 as the Out State service territory. Rate Area 3 is essentially the remainder of the Company's Nebraska service territory, excluding the Omaha area and Lincoln.

Q. For what customer classes are you determining the cost of service and rates?

A. The class cost of service study and rates that I have prepared in this case are specifically intended to address jurisdictional customer classes only. These customer classes include Residential, Commercial, and Energy Options Firm. Service to these classes is regulated by the Commission.

Q. Do you allocate costs to the non-jurisdictional customers?

A. Yes, I do. I further explain my method of allocating costs between jurisdictional and non-jurisdictional customers later in my testimony.

REVENUE SYNCHRONIZATION

Q. Please explain the revenue synchronization adjustment you are proposing.

A. The adjustment I am proposing simply synchronizes test year margin (revenues less cost of gas) with per books billing units and costs. I synchronize revenues for the Residential, Commercial, and Energy Options Firm classes for each jurisdictional rate area (Rate Areas 1, 2, and 3). I summarize these adjustments on Page 1 of Exhibit___(TJS-2).

Q. Why are you proposing to synchronize margins?

A. The primary reason is to provide a comparable basis upon which to compare revenues under existing and proposed rates. The revenue synchronization adjustment I am proposing results in revenues that are equal to per books billing units times the applicable existing rates. I can then add pro forma adjustments to sales, sales revenues, and numbers of customers to determine pro forma test period values. Since pro forma revenues are synchronized with pro forma sales, I can take the same pro forma test year billing units times the proposed rates and accurately measure the revenue impact of the rates I am proposing in this matter.

Q. Have you prepared an exhibit showing how these adjustments are calculated?

A. Yes, the detailed calculations of these adjustments for the Residential, Commercial, and Energy Options Firm classes for Rate Areas 1, 2, and 3 are shown on Page 2 of Exhibit___(TJS-2). As I show in this exhibit, total margin equals average annual number of customers (the number of bills actually rendered during the test year divided by 12) times existing customer charges times 12 plus total actual annual throughput times the existing commodity charge (exclusive of gas cost). This is synchronized sales margin, or, in other words, the amount of margin the Company would realize based on test year billing units and existing rates.

I compare this result against total revenues less purchased cost of gas revenues (per books margin) reported on the Company's books. The difference between these two values is the synchronization adjustment. I exclude the purchased cost of gas in my adjustment because the actual cost of gas and cost of gas revenues are accounted for separately in the Company's PGA. Over and under recovery mechanisms in the PGA insure that the Company collects 100 percent of its prudently incurred gas costs, nothing more, nothing less. Separate PGA proceedings or reviews deal with gas cost and gas cost revenues.

Q. What results are shown on Exhibit___(TJS-2)?

A. As shown on Page 1 of Exhibit___(TJS-2), the revenue synchronization adjustment to Rate Areas 1, 2, and 3 increases margin by $48,084, $163,128, and $12,620, respectively.

Q. How does Exhibit___(TJS-2) relate to Mr. Raab's proposed weather normalization adjustment, your class cost of service study, and your proposed rate design?

A. The synchronized revenues, cost of gas, and units of service (number of customers and volumes) contained in Exhibit___(TJS-2) represent test year figures prior to any other pro forma adjustments. I add the Company's other pro forma adjustments (Mr. Raab's proposed weather adjustment and the Company's Adjustment #2) to revenues, cost of gas, and sales volumes to the figures in Exhibit___(TJS-2) to produce pro forma test year revenues, cost of gas, and sales volumes that are used in my class cost of service study. I summarize the test year pro forma figures in Exhibit___(TJS-7) discussed later in my testimony.

Q. Does this conclude your prepared direct testimony regarding your proposed revenue synchronization adjustment?

A. Yes, it does.

ALLOCATION OF COSTS BETWEEN RATE AREAS

Q. Please outline the steps to determine the cost of service for jurisdictional customers.

A. I determine the cost of service for jurisdictional customers in three steps. First I allocate and assign costs between the Company's four Rate Areas (Step 1). Next, I functionally allocate these costs from Step 1 to Rate Areas 1, 2, and 3 (Step 2). I do not functionally allocate costs to Rate Area 4 since it is comprised of entirely non-jurisdictional customers and is not part of this rate case. I then allocate the functionalized costs to the jurisdictional customers to determine their cost of service (Step 3). In this section of my testimony, I discuss the first step - the allocation of costs between the Company's four Rate Areas. I discuss the functional and jurisdictional class cost of service study in the next section of my testimony.

Q. What data did the Company provide you?

A. The Company provided me with base year data and pro forma adjustments to arrive at test year data. I refer to base year data as unadjusted per books data as of June 30, 2006. The Company maintains its books so that a great deal of cost can be identified by rate area. However, some costs are not reported by rate area (I also may refer to these as "unallocated" costs). In addition, some costs reported by rate area are incurred for the benefit of customers outside the rate area reported. While the Company reports certain costs as directly applicable to Rate Area 4 (service to High-Volume, non-jurisdictional customers), these customers rely on facilities whose investment and costs are reported for Rate Areas 1, 2, and 3. In order to determine the jurisdictional revenue requirement (Step 3), I need to first determine the reasonable cost responsibility associated with serving the Rate Area 4 customers that is included in Rate Area 1 through 3 costs as reported by the Company.

Q. Do you maintain the direct assignments provided by the Company?

A. As I previously suggested, not always. For example, in my discussions with the Company, plant in service can easily be tied back to each rate area based on the service city where specific elements of plant are located. O&M expenses, on the other hand, are not always so readily identifiable. Generally, the amount of unallocated relative to the amount the Company directly assigned is greater with regard to O&M expenses than for plant in service. I therefore allocate the majority of O&M expenses.

In addition to direct assigning certain plant in service to rate areas, I direct assign working capital, gas storage inventory costs, acquisition adjustments, customer deposits, other operating revenues, and property taxes to rate areas. Other costs are generally allocated.

Q. Using the largest five FERC accounts as examples, please illustrate what bases you rely on to allocate costs among the rate areas.

A. Based on test year plant in service, the largest five FERC accounts are Distribution Mains (Account 376), Services (Account 380), Computer Equipment (Account 391.2), Meters (Account 381), and Other Equipment (Account 387), respectively.

I directly assign distribution mains to each respective rate area and allocate the "unallocated" to all rate areas on the basis of the direct assignments specific to that account. I then allocate (or credit) costs away from Rate Areas 1 through 3 to Rate Area 4 to reflect investment reported in Rate Areas 1, 2, and 3 that are needed to serve High-Volume Customers. In addition to the directly assigned Rate Area 4 plant, many of these High-Volume customers are served from the distribution system whose costs are reported with costs for Rate Areas 1 through 3. I therefore allocate a portion of the distribution system cost reported for Rate Areas 1 through 3 to Rate Area 4 (non-jurisdictional).

With regard to Account 380, I directly assign services to each respective rate area and allocate the "unallocated" to all rate areas on the basis of the direct assignments specific to that account.

I allocate Account 391.2, Computer Equipment, on the basis of supervised O&M, which is the same basis I use for all general plant.

With regard to Meters, Account 381, Aquila does not maintain cost of meters by state jurisdiction, therefore it is all unallocated. The Company allocates its total investment in meters to each of its state jurisdictions based on the number of meter sets in that state. Approximately thirty-seven percent of the number of meters in Account 381 is assigned to the Nebraska jurisdiction. I allocate Meters to each rate area on the basis of weighted average number of customers. The customer weighting factors reflect the detailed analysis contained in my workpapers specific to Aquila's

Nebraska jurisdiction which recognizes the relative cost of meters to serve the various customer classes, both jurisdictional and non-jurisdictional.

The Company books its automated meter reading (AMR) and related equipment to Account 387. Because AMR is specific to Lincoln (Rate Area 2), I break this account into AMR and other. I directly assign the AMR investment to Rate Area 2. I then directly assign the Other Equipment to the appropriate rate areas and allocate the "unallocated" on the basis of the direct assignments specific to that account (excluding AMR).

Q. Is the above discussion representative of how you assign and allocate costs between the Rate Areas?

A. Yes, it is.

Q. Have you prepared an exhibit that shows your allocation of costs between Rate Areas (Step 1)?

A. No, I have not. This analysis is contained in my workpapers filed with my direct testimony and exhibits.

Q. Does this conclude your prepared direct testimony regarding the allocation of costs between the Rate Areas?

A. Yes, it does.

JURISDICTIONAL CLASS COST OF SERVICE STUDY

Q. In the previous section, you mention that the second step in allocating costs to the jurisdictional customers is a functional cost of service study. Please explain what you mean by a functional cost of service study.

A. The detailed functional cost of service study (Step 2) that I prepared is contained in my workpapers. In that study, I assign and allocate Rate Area 1, 2, and 3 costs to the following functional cost categories: Supply; Peaking; Transmission Demand and Commodity; Distribution Demand, Commodity, and Customer; Services; Meters and Regulators; Customer Accounts; and Direct.

Q. Please provide some examples of how costs are assigned to cost functions in your functional cost of service study.

A. As an example, the plant investment in distributions mains (FERC accounts 376 and 377) is assigned to the Distribution Demand, Commodity, and Customer functions based on a detailed study (contained in my workpapers) of the Company's investment in distribution mains. Similarly, the plant investment associated with meters and regulators (FERC accounts 381 through 385) are assigned to the Meters and Regulators function.

Q. Please explain how the functional cost of service study is used to determine class cost of service.

A. The class allocation bases I develop in my class cost of service study are used to allocate these functional costs to customer classes, both jurisdictional and non-jurisdictional (Complaint-based). For example, Distribution Commodity related costs are allocated to customer classes classed based on annual throughput, and Meters and Regulators costs are allocated to customer classes based on number of customers weighted by the relative cost of meter and regulator sets for those customers.

Q. Have you prepared a functional cost of service study specifically for Aquila's jurisdictional customers?

A. No, I did not prepare a functional cost of service study specific to jurisdictional customers only. My functional cost of service study (Step 2) is based on costs allocated to each Rate Area (1, 2 and 3) from Step 1. As I explained earlier in my testimony, the costs I allocate to Rate Areas 1, 2, and 3 in Step 1 are attributable to both jurisdictional and non-jurisdictional customers (Complaint-based customers). I can then allocate the functional costs to the jurisdictional customer classes using appropriate allocation factors to determine the individual jurisdictional class costs of service.

Q. Please describe your jurisdictional class cost of service studies.

A. The class cost of service studies I sponsor are contained in Exhibits ___ (TJS-3) through (TJS-5). The jurisdictional class cost of service studies for Rate Areas 1, 2 and 3 are based upon operations for the twelve month period ended June 30, 2006 as adjusted for known and measurable changes. Exhibits ___ (TJS-3) through (TJS-5) show the jurisdictional class cost of service studies for the jurisdictional customer classes only (Residential, Commercial, and Energy Options Firm) for Rate Areas 1, 2, and 3, respectively. The cost of service for these jurisdictional customer classes shown in Exhibits ___ (TJS-3) through (TJS-5) differs from the total functional cost of service studies for each of the Rate Areas by the amount of costs that I allocate to the non-jurisdictional (Complaint-based) customers.

Q. Please discuss the contents of Exhibits ___ (TJS-3) through (TJS-5).

A. Exhibits ___(TJS-3) through (TJS-5) set forth the results of allocating the functionally classified costs to the jurisdictional customer classes (Residential, Commercial, and Energy Options Firm) for Rate Areas 1, 2, and 3, respectively. Exhibits___(TJS-3) through (TJS-5) consist of five tables as follows:

1. Table 1 shows the development of class rates of return under current and cost of service rates.
2. Table 2 shows the allocation bases used to allocate functional cost of service to customer classes.
3. Table 3 shows the allocation of functional rate base to customer classes.
4. Table 4 shows the allocation of functional cost of service to customer classes.
5. Tables 5 shows the unit ($/therm or $/bill) functionalized cost of service.

Q. What customer classes do you show in your cost of service study?

A. I show three customer classes in my cost of service study. These are Residential, Commercial, and Energy Options Firm. Energy Options Firm class includes service to Commercial customers who choose a gas supplier other than Aquila. The Energy Options Firm class represents service to non-complaint customers subject to regulation by the Commission.

Q. Please discuss the principal allocation bases used in your class cost of service study.

A. Table 2 of Exhibits ___ (TJS-3) through (TJS-5) shows the allocation factors I use to allocate functionally classified costs to the three customer classes for each of the three jurisdictional Rate Areas, respectively.

Winter peak demand represents estimated class peak day requirements. The peak day requirements for the three customer classes are estimated based on regression analysis of monthly sales and heating degree-days and analysis of peak month throughput to average throughput. This allocation basis is used to allocate capacity related costs.

Winter period throughput represents test year throughput for each class during the months of November through March. This allocation basis is used to allocated capacity related costs. Firm winter period sales excludes interruptible customers. This allocation bases is used to allocate peaking related costs.

Commodity represents the fully adjusted test year throughput associated with each customer class. This allocation basis is used to allocate costs that vary with annual purchased volumes.

The distribution-customer, services, meters and regulators, and customer accounting allocation bases are developed by weighting average number of customers and are used to allocate the corresponding functionalized costs. Number of customers is weighted by factors that represent the relative cost or investment associated with service to each class.

Q. How do you allocate functionally classified costs to customer classes?

A. Gas supply costs are allocated to each customer class based the cost of gas. Peaking costs are allocated based on firm winter period sales.

Transmission and distribution demand related costs are allocated to classes using an approach that results in 50 percent of the costs being allocated on the basis of winter period throughput and 50 percent of the costs being allocated on the winter period peak demand. Transmission and distribution commodity related costs are allocated to customer classes using the annual throughput allocation basis.

Distribution customer, services, meters and regulators, and customer accounting related costs are allocated to classes on the basis of weighted number of customers. Weighting factors are used for each functional classification in order to recognize the relative difference in costs in serving the various customer classes.

Q. What are the principal findings of your study?

A. The principal findings for Aquila's Nebraska gas utility operations in each of three jurisdictional Rate Areas for jurisdictional customers (Residential, Commercial, and Energy Options) are summarized in the following table:

Finding	Rate Area 1	Rate Area 2	Rate Area 3
Overall Rate of Return under Current Rates	-0.59%	4.09%	2.10%
Jurisdictional Rate Base	$30,254,484	$64,318,740	$43,849,026

Rates of return under current rates in each of the three Rate Areas for Nebraska jurisdictional sales customer classes are summarized in the following table:

Customer Class	Rate Area 1	Rate Area 2	Rate Area 3
Residential Service	-1.01 percent	2.32 percent	0.67 percent
Commercial Service	-0.54 percent	9.15 percent	3.54 percent
Energy Options Firm	7.78 percent	12.96 percent	9.95 percent

As indicated by the rates of return under current rates, current rate revenues associated with Aquila's service to Nebraska jurisdictional customers are insufficient to cover cost, including an opportunity for the Company to earn a reasonable return on its investment devoted to public service. In order for the Company to earn the 9.60 percent rate of return claimed by the Company, current Nebraska jurisdictional rate revenues must be increased by approximately $16.3 million.

Q. Does this conclude your prepared direct testimony regarding your class cost of service study?

A. Yes, it does.

PROPOSED RATE DESIGN

Q. What customer categories does Aquila propose to rate increase in this case?

A. The Company is proposing increased rates for service to jurisdictional customers only. I sponsor the Company proposed rates for the Residential and Commercial rate schedules. The Energy Options Firm customers pay the same customer charge and commodity rate as the Commercial customers.

Q. Are there other customers served by Aquila in Nebraska?

A. Yes. As I mentioned earlier in my testimony, Aquila also serves non-jurisdictional customers. The Company is not proposing to change these customers' rates in this proceeding.

Q. What guidelines did you follow in the design of proposed rates?

A. The guidelines are as follows:

1. Customer charges should more directly reflect customer related costs.
2. The overall rate increase should be approximately $16.3 million.
3. The customer and commodity charges for the Commercial and Energy Options service should be equal.
4. The commodity charges should be equalized among the three rate areas similar to the existing customer charges.
5. Consistent with the above goals, rates should be designed as near to cost of service as practical.

Q. Have you prepared any exhibits summarizing your proposed rates?

A. Yes. Exhibit ___ (TJS-6) summarizes my proposed rates. Exhibit ___ (TJS-7) is a detailed calculation of revenues under current and proposed rates. Columns B though J of Exhibit___(TJS-7) show the derivation of revenues under current rates. Columns K through M show the cost of service, indicated deficiency, and rate of return under current rates, respectively, as determined in Exhibits___(TJS-3) through (TJS-5). Columns N though T show the derivation of revenues under proposed rates. Columns U through Y show a comparison between revenues under current and proposed rates. Rate of return under proposed rates is shown in Columns Z and AA.

Q. Are you proposing to change the fundamental rate structure?

A. No, I propose to maintain the existing rate structure which consists of a fixed monthly customer charge and a flat commodity (volumetric) charge applicable to all customers within a given rate schedule.

Q. What proposed rates are you recommending with regard to customer charges?

A. My class cost of service study (Table 5 of Exhibit___(TJS-3) through Exhibit ___(TJS-5)) indicates the following customer related costs for each of the classes by rate area

Customer Class	Rate Area 1 $/bill	Rate Area 2 $/bill	Rate Area 3 $/bill
Residential Service	$18.52	$15.81	$17.45
Commercial/EO Service	$43.04	$38.07	$41.02

These unit costs represent the maximum level of customer charges that can be justified on the basis of average class cost as measured by my cost of service study.

Under the current rates, the customer charges are equalized among the rate areas. Consistent with this methodology, I recommend the Residential customer charge be increased to $16.00 per month from the current customer charge of $11.00 per month. I recommend that the customer charge for the Commercial rate be increased to $20.00 per month from the current customer charge of $15.00 per month. Generally, my recommended customer charges do not fully recover the customer related costs identified in my class cost of service study, but they move more closely toward the customer related costs determined by my study.

Q. What rates are you recommending with regard to the non-gas commodity rate (margin) for each rate schedule?

A. I recommend that the commodity charges be equalized among the rate areas. I recommend this change for several reasons. First, the existing commodity charges are not that different from each other. The Residential commodity charges only vary by a few cents among the rate areas. The Commercial/EO commodity charges for Rate Areas 2 and 3 are also very close. There is not enough real difference to justify three different rates for each customer class. Second, while each rate area is unique, the relative cost of service is not significantly different. For example, although Rate Area 2 has lower O&M expenses because of the AMR system, it has a proportionately larger investment. Lastly, the rate design that I am proposing is simple and easy to understand.

The table below sets forth my proposed changes with regard to the commodity charges.

	Existing			
Customer Class	Rate Area 1 $/therm	Rate Area 2 $/therm	Rate Area 3 $/therm	Proposed $/therm
Residential Service	0.10967	0.11070	0.12177	0.14868
Commercial/EO Service	0.12700	0.15922	0.15266	0.15803

Q. How did you determine the Residential commodity charge?

A. The Residential commodity charge that I propose is the level required to fully recover the sum of the three rate areas' Residential cost of service not otherwise collected through the proposed customer charge. In other words, all fixed capacity costs not recovered through the customer charge are recovered through the commodity charge.

Q. How did you determine the Commercial/Energy Options commodity charge?

A. I determined the Commercial/Energy Options commodity charge in the same manner as the Residential commodity charge – it is the level required to fully recover the sum of the three rate areas' Commercial/Energy Options cost of service not otherwise collected through the proposed customer charge.

Q. Please discuss the impact of your proposed rates by rate schedule and by rate area.

A. The increases (amount and percentage) by rate class and rate area shown in Columns U through Y of Exhibit ___ (TJS-7). I summarize the impact of my proposed rates in the following table.

	Proposed Increase					
Customer Class	Rate Area 1		Rate Area 2		Rate Area 3	
	$	%	$	%	$	%
Residential	$3,277,457	9.59%	$7,130,866	10.83%	$4,304,902	8.05%
Commercial/EO	$545,232	5.80%	$427,670	1.65%	$608,540	2.88%
Total	$3,822,689	8.77%	$7,558,537	8.24%	$4,913,442	6.58%

Q. How do your proposed rates compare to cost of service?

A. As previously discussed in my testimony, the proposed rates for the Residential and Commercial/EO classes are designed to recover each classes' indicated cost of service and I am proposing to equalize the rates among the rate areas. Therefore, the rates of return under proposed rates for these classes for combined Rate Areas 1, 2, and 3 is 9.60 percent equals the overall rate of return requested by the Company of 9.60 percent. I show these results in Columns Z and AA, Lines 2-4 of Exhibit ___ (TJS-7).

Q. Are the proposed rates you discuss in this section the rates used by Mr. Raab for his recommended RNA?

A. Yes, they are.

Q. Does this complete your prepared direct testimony regarding your proposed rate design?

A. Yes, it does.

ALTERNATE RATE DESIGNS

Q. Have you prepared any alternate rate designs?

A. Yes, I have. In order to recognize the predominantly fixed nature of the Company's revenue requirement, in other words non-gas costs do not vary significantly with the volume of gas sold or delivered, I have prepared two alternate rate designs that diverge from the traditional rate design approach. Historically, the Company's level of customer charges have been limited by the level of customer related costs. In order to recognize the predominately fixed nature of all of the Company's non-gas costs, I have prepared two rate design alternatives that maintain the traditional commodity and customer charge rate structure, but collect more of the revenue requirement through the customer charge. Both of these alternatives, based on the Company's proposed revenue requirement, result in customer charges that exceed direct customer related costs.

Q. Why did you prepare these two alternative rate designs?

A. I prepared these rate designs in order to provide a comparison of other possible approaches to deal with the mismatch which results because the traditional rate design relies heavily on collecting revenues through a variable volumetric component when most of the Company's costs do not vary with the volume of gas delivered. In the last section of my direct testimony I compare these two rate designs to the rates I am proposing.

Q. Please describe these two alternative rate designs.

A. In the first alternative, I calculate rates as though 100 percent of the requested revenue increase is collected by increasing only the customer charge and the level of revenues collected through the commodity charge is unchanged. In the second alternative, I calculate rates as though 100 percent of the requested revenue requirement is collected through the customer charge and the commodity charge is set equal to zero.

Q. Please describe how you calculated the rates assuming the 100 percent of the proposed increase is collected through increasing the customer charge.

A. The criteria that I followed are:

1. Equalize the existing commodity charge among the rate areas for the Residential and Commercial/EO classes as I did in the rates I am proposing.
2. Recover the full amount of the Company's deficiency in an equalized customer charge among the rate areas for the Residential and Commercial/EO classes.
3. Design rates for each customer class by indicated class cost of service.

Using these three criteria, I calculate the following charges:

Customer Class	Customer Charge $/bill/month	Commodity Charge $/therm
Residential Service	$18.07	$0.11409
Commercial/EO Service	$21.96	$0.15139

I show the detailed calculation revenues under current and this first alternative rate design (100 percent of the proposed increase is collected through increasing the customer charge) in Exhibit ___ (TJS-8). Exhibit ___ (TJS-8) is in the same general format as Exhibit ___ (TJS-7).

Q. Please describe how you determined the flat charge that would be necessary to collect 100 percent of the Company's proposed revenue requirement.

A. I determined the flat charge that would collect the same indicated cost of service in total as the traditional rate design I am proposing for the combined Residential and

Commercial/EO customer classes. I calculate the flat charge by taking the Residential and Commercial/EO cost of service requirement as determined in my cost of service study and dividing by the number of annual bills. The flat charge that results is a $29.01 per bill per month charge for Residential and Commercial/EO customers. The table below presents the calculation:

	Cost of Service	Number of Customers
Residential	$51,812,123	173,463
Commercial/EO	$15,154,702	18,931
Total	$66,966,824	192,394
Flat Charge		$29.01/bill/month

I show the detailed calculation revenues under current and flat charge rate design in Exhibit ___ (TJS-9). Exhibit ___ (TJS-9) is in the same general format as Exhibits ___ (TJS-7) and (TJS-8).

Q. Has the flat charge rate design either been accepted or proposed in other jurisdictions?

A. Yes, it has. In Case No. PU-400-04-578, the North Dakota Public Service Commission accepted a flat charge rate design for Northern States Power Company's residential class. The residential flat charge is $15.68 per month.

Ms. Anne Ross, Missouri Public Service Commission Staff, proposed a flat charge rate for the Atmos' residential class in her rebuttal testimony in Case No. GR-2006-0387. In addition, both the Staff and the Company are proposing a flat charge in Missouri Gas Energy's current case in Case No. GR-2006-0422. These cases are still pending.

Q. Does this conclude your prepared direct testimony regarding the alternate rate designs?

A. Yes, it does.

COMPARISON OF PROPOSED TRADITIONAL RATE DESIGN TO ALTERNATE RATE DESIGNS

Q. Have you prepared comparisons of the bill impacts of the proposed rate design and the two alternatives?

A. Yes. Exhibit___(TJS-10) shows a comparison of typical bills for small, medium, and large Residential and Commercial/EO customers under the Company's existing rates, proposed rates, and the two alternatives incorporating the Company's requested revenue deficiency. In my Exhibit___(TJS-10), I refer to the rate design where I collect 100 percent of the requested revenue increase by increasing only the customer charge and keeping the commodity charge unchanged as Alternative 1. Alternative 2 is the flat charge rate design.

Q. In regards to Exhibit___(TJS-10), do you have any general observations before discussing the bill impacts of the proposed rate design and alternatives?

A. Yes. Exhibit ___ (TJS-10) indicates that under existing rates the typical bills for each rate area are fairly similar. This observation is consistent with my earlier statement that there is not enough real difference to justify three different rates for each customer class, and, therefore, reinforces my proposal to equalize commodity rates in addition to customer charges.

Q. With regard to typical bills, how do your proposed rates compare to Alternative 1?

A. Small Residential customers would pay less under my proposed rates than they would under Alternative 1. There is not much difference between my proposed rates and Alternative 1 for small Commercial customers. However, the typical medium and large customer (both Residential and Commercial) would pay less under Alternative 1.

Q. With regard to typical bills, how do your proposed rates compare to Alternative 2?

A. Small and medium Residential customers would pay more and large Residential and Commercial customers would pay less under Alternative 2 as compared to my proposed rate design.

Q. What are the advantages of the rate design that collects 100 percent of the increase by increasing the customer charge (Alternative 1)?

A. Compared to the traditional rate design (without a revenue normalization adjustment), this rate design better recognizes the fixed nature of the Company's non-gas costs by collecting a higher percentage of the revenue requirement through the customer charge versus the commodity (or volumetric) charge. In addition, it maintains the existing rate structure with which customers are familiar.

Q. What are the disadvantages of Alternative 1?

A. This rate design collects fixed costs that are not customer specific without recognizing the differences in cost to serve customers of different size who create different capacity requirements. Further, it does not go far enough in recognizing the fixed nature of the Company's non-gas costs. At best, it is small step in that direction.

Q. What are the advantages of a flat charge rate design (Alternative 2)?

A. The flat charge is the simplest form of rate design. It eliminates any disincentive for the Company to encourage conservation and energy efficiency plans. Under a flat charge, the Company is indifferent to conservation. In addition, there is no seasonality in the non-gas portion of a customer's bill which better aligns the monthly recovery of cost through rates with the Company's monthly incurrence of costs. From the perspective of the customer, the rate design is easy to understand and it reduces the effects of weather on customer bills. In turn, it reduces the variability of the Company's revenue stream and would totally eliminate the need for the Company to administer a revenue normalization adjustment (RNA) rider or a weather normalization adjustment (WNA) rider.

Q. What are the disadvantages of a flat charge rate design?

A. Even more so than Alternative 1, the flat charge rate design does not recognize differences in cost to serve customers of different size who create different capacity requirements. It treats all customers the same, regardless of their size or demand on the system.

Q. What are the advantages of your proposed traditional rate design over the two alternative rate designs?

A. It maintains the existing rate structure with which the customers are familiar. It recognizes the difference in capacity requirements needed to serve customers of different size, the more a customer uses or demands (i.e. the larger the customer), the more they pay through the commodity portion of the rate. By combining the traditional rate design with the RNA proposed by Mr. Raab, the proposed rate design overcomes the issue of there being a mismatch between the fixed nature of the Company's cost and collecting a large percentage of these costs through a variable or volumetric rate components. This advantage is more fully discussed in Mr. Raab's testimony.

Q. Please summarize which rate design you recommend for Aquila?

A. I believe that the best rate design at this time is the traditional rate design coupled with the Company's proposed RNA. This rate design is contained in my Exhibit___(TJS-6).

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

Expert Witness Testimony of Thomas J. Sullivan

- *Peoples Natural Gas Company of South Carolina, South Carolina Public Service Commission Docket No. 88-52-G (1988).* Natural gas utility revenue requirements and rate design.

- *Peoples Natural Gas (UtiliCorp United, Inc.), Iowa Utilities Board Docket No. RPU-92-6 (1992).* Natural gas utility class cost of service study and peak day demand requirements.

- *Peoples Natural Gas (UtiliCorp United, Inc.), Kansas Corporation Commission Docket No. 193,787-U (1996).* Natural gas utility class cost of service study, rate design, and peak day demand requirements.

- *Southern Union Gas Company, Railroad Commission of Texas Gas Utilities Docket No. 8878 (1998).* Natural gas utility depreciation rates.

- *Southern Union Gas Company, City of El Paso (1999).* Natural Gas utility depreciation rates.

- *UtiliCorp United, Inc., Kansas Corporation Commission Docket No. 00-UTCG-336-RTS (1999).* Natural gas utility weather normalization, class cost of service, and rate design.

- *Philadelphia Gas Works, Pennsylvania Public Utility Commission Docket No. R-00006042 (2001)*. Natural gas utility revenue requirements.

- *Missouri Gas Energy, Missouri Public Service Commission Docket No. GR-2001-292 (2001).* Natural gas utility depreciation rates.

- *Aquila Networks, Iowa Utilities Board Docket No. RPU-02-5 (2002).* Natural gas utility class cost of service study, rate design, and weather normalization adjustment.

- *Aquila Networks, Michigan Gas Utilities, Michigan Public Service Commission Case No. U-13470 (2002).* Natural gas utility class cost of service study, rate design, and weather normalization adjustment.

- *Aquila Networks, Nebraska Public Service Commission Docket No. NG-0001, NG0002, NG0003 (2003).* Natural gas utility weather normalization adjustment.

- *Aquila Networks, Missouri Public Service Commission Docket No. GR-2003 (2003).* Natural gas utility class cost of service study, rate design, annualization adjustment, and weather normalization adjustment.

- *North Carolina Natural Gas, North Carolina Utilities Commission Docket No. G-21-Sub 442 (2003).* Filed intervenor testimony on behalf of the municipal customers regarding natural gas cost of service and rates related to intrastate transmission service.

- *Texas Gas Service Company, Division of ONEOK, Railroad Commission of Texas Gas Utilities Docket No. 9465 (2004)*. Natural gas utility depreciation rates.

- *Missouri Gas Energy, Missouri Public Service Commission Docket No. GR-2004-0209 (2004).* Natural gas utility depreciation rates.

- *Aquila Networks, Kansas Corporation Commission Docket No. 05-AQLG-367-RTS (2004).* Natural gas utility class cost of service study, rate design, and weather normalization adjustment.

- *Aquila Networks, Iowa Utilities Board Docket No. RPU-05-02 (2005).* Natural gas utility class cost of service study, rate design, grain drying adjustment and weather normalization adjustment.

- *PJM Interconnection, LLC, Federal Energy Regulatory Commission Docket No. ER05-1181 (2005).* Operating cash reserve requirements.

- *Kinder Morgan, Inc., Wyoming Public Service Commission Docket No. 30022-GR-6-73 (2006)*. Natural gas utility weather normalization adjustment, development of load factors, billing cycle adjustment, determination of test year billing units and revenue, and depreciation rates.

- *Missouri Gas Energy, Missouri Public Service Commission Docket No. GR-2006-0422 (2006)*. Natural gas utility depreciation rates.

- *Kinder Morgan, Inc., Nebraska Public Service Commission Docket No. NG-0036 (2006)*. Natural gas utility weather normalization adjustment, test year billing determinates and revenue under existing rates, customer and usage trends, and rate design.

- *Aquila Networks, Kansas Corporation Commission Docket No. 07-AQLG-431-RTS (2006).* Natural gas utility class cost of service study, rate design, irrigation adjustment, and weather normalization adjustment.

Aquila Networks - NE
Summary of Jurisdictional Synchronization Adjustment

	Total Revenues	Cost of Gas	Margin
	$	$	$
Rate Area 1			
Per Books			
Residential	31,162,043	23,605,937	7,556,106
Commercial	8,024,805	6,594,579	1,430,226
Energy Options	430,998	-	430,998
Total Rate Area 1	39,617,846	30,200,516	9,417,330
Synchronized Revenue			
Residential			7,603,609
Commercial			1,435,765
Energy Options			426,041
Total Rate Area 1			9,465,414
Synchronization Adjustment for Rate Area 1			48,084
Rate Area 2			
Per Books			
Residential	59,500,332	43,165,494	16,334,838
Commercial	22,194,190	17,927,006	4,267,184
Energy Options	1,463,188	-	1,463,188
Total Rate Area 2	83,157,710	61,092,500	22,065,210
Synchronized Revenue			
Residential			16,508,556
Commercial			4,275,514
Energy Options			1,444,269
Total Rate Area 2			22,228,338
Synchronization Adjustment for Rate Area 2			163,128
Rate Area 3			
Per Books			
Residential	47,995,038	36,616,702	11,378,336
Commercial	17,161,318	14,059,506	3,101,812
Energy Options	1,889,659	-	1,889,659
Total Rate Area 3	67,046,015	50,676,208	16,369,807
Synchronized Revenue			
Residential			11,433,572
Commercial			3,104,863
Energy Options			1,843,992
Total Rate Area 3			16,382,427
Synchronization Adjustment for Rate Area 3			12,620
Total Synchronization Adjustment			223,832

Aquila Networks - NE
Jurisdictional Revenue Synchronization Adjustment

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
	Existing		Per Books			Synchronized				
	Customer Charge	Commodity Charge	Number of Customers	Throughput	Revenue	Customer Charge	Commodity Charge	Cost of Gas	Total Revenues	Synchron. Adjustment
	$/bill/mo	$/therm		dt		$	$	$	$	$
Rate Area 1										
Residential	11.00	0.10967	36,423	2,549,288	31,162,043	4,807,804	2,795,804	23,605,937	31,209,546	47,503
Commercial	15.00	0.12700	2,920	716,665	8,024,805	525,600	910,165	6,594,579	8,030,344	5,539
Energy Options Firm	15.00	0.12700	473	268,426	430,998	85,140	340,901	-	426,041	(4,957)
Total			39,816	3,534,379	39,617,846	5,418,544	4,046,870	30,200,516	39,665,930	48,084
Rate Area 2										
Residential	11.00	0.11070	83,700	4,932,390	59,500,332	11,048,400	5,460,156	43,165,494	59,674,050	173,718
Commercial	15.00	0.15922	6,078	1,998,162	22,194,190	1,094,040	3,181,474	17,927,006	22,202,520	8,330
Energy Options Firm	15.00	0.15922	1,647	720,895	1,463,188	296,460	1,147,809	-	1,444,269	(18,919)
Total			91,425	7,651,447	83,157,710	12,438,900	9,789,438	61,092,500	83,320,838	163,128
Rate Area 3										
Residential	11.00	0.12177	53,467	3,593,601	47,995,038	7,057,644	4,375,928	36,616,702	48,050,274	55,236
Commercial	15.00	0.15266	5,492	1,386,285	17,161,318	988,560	2,116,303	14,059,506	17,164,369	3,051
Energy Options Firm	15.00	0.15266	2,321	934,241	1,889,659	417,780	1,426,212	-	1,843,992	(45,667)
Total			61,280	5,914,127	67,046,015	8,463,984	7,918,443	50,676,208	67,058,635	12,620
Total Rate Areas 1-3			**192,521**	**17,099,953**	**189,821,571**	**26,321,428**	**21,754,751**	**141,969,224**	**190,045,403**	**223,832**

Aquila Networks - NE Rate Area 1 - Jurisdictional
Rate of Return Under Current and Cost of Service Rates
Test Year Ended June 30, 2006

	[A]		[B]	[C]	[D]	[E]	[F]
Line Number	Description		Total Res, Comm, Energy Options	Residential	Commercial	Energy Options Firm	Basis of Allocation or Reference
			$	$	$	$	
1	Return Under Existing Rates						
2	Rate Base		30,254,484	24,034,319	5,047,006	1,173,158	
3	Sales Revenues		43,563,588	34,162,155	8,937,789	463,644	
4	Cost of Gas		33,671,756	26,279,380	7,392,376	-	
5	Sales Revenues Excluding Gas Cost		9,891,831	7,882,775	1,545,413	463,644	
6	Net Cost of Service		14,958,153	12,072,589	2,386,792	498,772	
7	Revenue Deficiency		5,066,322	4,189,814	841,379	35,129	
8	Percent - Total Sales with Gas Cost		11.63%	12.26%	9.41%	7.58%	
9	Proposed Increase		3,822,689	3,277,457	424,372	120,860	
10	Percent - Total Sales with Gas Cost		8.77%	9.59%	4.75%	26.07%	
11	Incremental Taxes at	39.15%	1,496,758	1,283,275	166,161	47,322	
12	Incremental Return		2,325,930	1,994,182	258,211	73,538	
13	Return Under Proposed Rates		2,147,737	1,752,167	230,783	164,787	
14	Rate of Return Under Proposed Rates		7.10%	7.29%	4.57%	14.05%	
15	Return Under Current Rates		(178,193)	(242,014)	(27,428)	91,249	
16	Rate of Return Under Current Rates		-0.59%	-1.01%	-0.54%	7.78%	

Aquila Networks - NE Rate Area 1 - Jurisdictional
Customer Group Allocation Basis
Test Year Ended June 30, 2006

Exhibit___(TJS-3)
Table 2 of 5

Line Number	Description [A]		Total Res, Comm, Energy Options [B]	Residential [C]	Commercial [D]	Energy Options Firm [E]	Basis of Allocation or Reference [F]
			$	$	$	$	
	Allocation Bases						
1	1. Winter Period Peak Demand	Load Factor		23.73%	24.22%	24.22%	
2	Peak Day - Dth/Day		45,005	32,550	9,083	3,371	Line 11 / 365 / Line 1
3	Allocation Factor		100.0000%	72.3264%	20.1828%	7.4908%	Line 2 / Column B, Line 2
4	2. Winter Period Throughput						
5	Winter (Nov-Mar) Throughput - Dth		2,874,419	2,088,145	565,396	220,878	
6	Allocation Factor		100.0000%	72.6458%	19.6699%	7.6843%	Line 5 / Column B, Line 5
7	3. Firm Winter Period Sales						
8	Winter (Nov-Mar) Sales - Dth		2,874,419	2,088,145	565,396	220,878	Line 5
9	Allocation Factor		100.0000%	72.6458%	19.6699%	7.6843%	Line 8 / Column B, Line 8
10	4. Commodity						
11	Annual Throughput - Dth		3,920,111	2,819,074	803,002	298,034	
12	Allocation Factor		100.0000%	71.9131%	20.4842%	7.6027%	Line 11 / Column B, Line 11
13	5. Services						
14	Average Number of Customers		39,689	36,296	2,920	473	
15	Weighting Factor			1.00	2.00	2.00	Customer Plant Use Study
16	Weighted Number of Customers		43,082	36,296	5,840	946	Line 14 x Line 15
17	Services Cost Allocator		100.0000%	84.2486%	13.5555%	2.1958%	Line 16 / Column B, Line 16
18	6. Meters & Regulators						
19	Average Number of Customers		39,689	36,296	2,920	473	
20	Weighting Factor			1.00	3.50	3.50	Customer Plant Use Study
21	Weighted Number of Customers		48,172	36,296	10,220	1,656	Line 19 x Line 20
22	Meters & Regulators Cost Allocator		100.0000%	75.3475%	21.2159%	3.4367%	Line 21 / Column B, Line 21
23	7. Customer Accounts						
24	Average Number of Customers		39,689	36,296	2,920	473	
25	Weighting Factor			1.00	2.00	2.00	
26	Weighted Number of Customers		43,082	36,296	5,840	946	Line 24 x Line 25
27	Customer Accounts Cost Allocator		100.0000%	84.2486%	13.5555%	2.1958%	Line 26 / Column B, Line 26
28	Annual Use per Customer - Dth		1,185	932	3,300	7,561	Line 11 / Line 14 x 12
Summary							
29	Supply - Gas Purchases		100.00%	78.05%	21.95%	0.00%	
30	Peaking		100.00%	72.65%	19.67%	7.68%	
31	Transmission Demand		100.00%	72.49%	19.93%	7.59%	
32	Transmission Commodity		100.00%	71.91%	20.48%	7.60%	
33	Distribution Demand		100.00%	72.33%	20.18%	7.49%	
34	Distribution Commodity		100.00%	71.91%	20.48%	7.60%	
35	Distribution Customer		100.00%	84.25%	13.56%	2.20%	
36	Services		100.00%	84.25%	13.56%	2.20%	
37	Meters & Regulators		100.00%	75.35%	21.22%	3.44%	
38	Customer Accounts		100.00%	84.25%	13.56%	2.20%	

Aquila Networks - NE Rate Area 1 - Jurisdictional
Allocation of Rate Base to Customer Classes
Test Year Ended June 30, 2006

	[A]	[B]	[C]	[D]	[E]	[F]
Line Number	Description	Total Res, Comm, Energy Options	Residential	Commercial	Energy Options Firm	Basis of Allocation or Reference
		$	$	$	$	
1	Rate Base					
2	Supply	442,807	345,592	97,215	0	Cost of Gas
3	Peaking	3,422,844	2,486,553	673,271	263,020	Firm Winter Period Sales
4	Transmission					
5	Demand	5,935	4,302	1,183	450	50% Winter Period Peak Demand, 50% Winter Period Throughput
6	Commodity	5,882	4,230	1,205	447	Commodity
7	Total Transmission	11,817	8,532	2,388	897	Line 5 + Line 6
8	Distribution					
9	Demand	3,930,388	2,842,707	793,262	294,419	Winter Period Peak Demand
10	Commodity	1,144,394	822,969	234,420	87,005	Commodity
11	Customer	6,609,017	5,568,007	895,888	145,122	Services
12	Total Distribution	11,683,799	9,233,684	1,923,570	526,546	Sum of Lines 9 through 11
13	Services	8,210,176	6,916,962	1,112,934	180,280	Services
14	Meters and Regulators	4,594,332	3,461,713	974,727	157,892	Meters & Regulators
15	Customer Accounts	1,496,069	1,260,418	202,800	32,851	Customer Accounts
16	Direct					
17	Other Cash Working Capital	392,639	320,866	60,102	11,671	Supervised O&M
18	Total Rate Base	30,254,484	24,034,319	5,047,006	1,173,158	Sum of Lines 2, 3, 7, 12, 13,14, 15 and 16

Aquila Networks - NE Rate Area 1 - Jurisdictional
Allocation of Cost of Service to Customer Classes
Test Year Ended June 30, 2006

	[A]	[B]	[C]	[D]	[E]	[F]
Line Number	Description	Total Res, Comm, Energy Options	Residential	Commercial	Energy Options Firm	Basis of Allocation or Reference
		$	$	$	$	
1	Total Cost of Service					
2	Supply	59,856	46,715	13,141	0	Cost of Gas
3	Peaking	462,676	336,115	91,008	35,553	Firm Winter Period Sales
4	Transmission					
5	Demand	4,970	3,603	991	377	50% Winter Period Peak Demand, 50% Winter Period Throughput
6	Commodity	49,645	35,701	10,169	3,774	Commodity
7	Total Transmission	54,615	39,304	11,160	4,151	Line 5 + Line 6
8	Distribution					
9	Demand	1,488,641	1,076,680	300,449	111,512	50% Firm Winter Period Peak Demand, 50% Firm Winter Period Throughput
10	Commodity	653,831	470,190	133,932	49,709	Commodity
11	Customer	2,366,118	1,993,422	320,740	51,956	Services
12	Total Distribution	4,508,590	3,540,293	755,121	213,176	Sum of Lines 9 through 11
13	Services	3,685,542	3,105,019	499,595	80,928	Services
14	Meters and Regulators	2,131,412	1,605,965	452,197	73,250	Meters & Regulators
15	Customer Accounts	4,104,929	3,458,347	556,446	90,137	Customer Accounts
16	Direct					
17	Other Cash Working Capital	53,074	43,372	8,124	1,578	Supervised O&M
18	Forfeited Discounts	(102,541)	(102,541)	-	-	Direct
19	Total Cost of Service	14,958,153	12,072,589	2,386,792	498,772	Sum of Lines 2, 3, 7, 12, 13,14, 15 , 17 and 18

Aquila Networks - NE Rate Area 1 - Jurisdictional
Cost of Service Rate Design
Test Year Ended June 30, 2006

	[A]	[B]	[C]	[D]	[E]	[F]
Line Number	Description	Total Res, Comm, Energy Options	Residential	Commercial	Energy Options Firm	Basis of Allocation or Reference
		$	$	$	$	
1	Supply - Commodity - $	59,856	46,715	13,141	0	Line 1 ,Table 2
2	$/Dth	0.0153	0.0166	0.0164	0.0000	Line 1 / Line 11 ,Table 4
3	Peaking - Demand - $	462,676	336,115	91,008	35,553	Line 3 ,Table 2
4	$/Dth	0.1180	0.1192	0.1133	0.1193	Line 3 / Line 11 ,Table 4
5	Transmission - Demand -$	4,970	3,603	991	377	Line 5 ,Table 2
6	$/Dth	0.0013	0.0013	0.0012	0.0013	Line 5 / Line 11 ,Table 4
7	Transmission - Commodity - $	49,645	35,701	10,169	3,774	Line 6 ,Table 2
8	$/Dth	0.0127	0.0127	0.0127	0.0127	Line 7 / Line 11 ,Table 4
9	Distribution - Demand - $	1,541,716	1,120,053	308,573	113,089	Line 9, Table 2
10	$/Dth	0.3933	0.3973	0.3843	0.3795	Line 9 / Line 11 ,Table 4
11	Distribution - Commodity - $	653,831	470,190	133,932	49,709	Line 10, Table 2
12	$/Dth	0.1668	0.1668	0.1668	0.1668	Line 11 / Line 11 ,Table 4
13	Distribution - Customer - $	2,366,118	1,993,422	320,740	51,956	Line 11 ,Table 2
14	$/Dth	0.6036	0.7071	0.3994	0.1743	Line 13 / Line 11 ,Table 4
15	Customer Accounts Related - $	9,819,342	8,066,790	1,508,238	244,314	Line 13 + Line 14 + Line 15 + Line 18, Table 2
16	$/month	20.62	18.52	43.04	43.04	Line 15 / Line 24 ,Table 4 / 12
17	Total Demand - $/Dth		1.2249	0.8983	0.6743	Line 6+Line 10+Line 14
18	Total Commodity - $/Dth		0.1960	0.1958	0.1795	Line 8+Line 12
19	Total - $/Dth		1.4210	1.0941	0.8538	Line 17+Line 18
20	Customer Charge - $/mth		16.00	20.00	20.00	Proposed Rates
21	Volumetric Charge - $/Dth		1.8104	2.0996	1.2926	(Line 22 - Line 20 X Line 24 X 12) / Line 11
22	Total Cost of Service - $	14,958,153	12,072,589	2,386,792	498,772	(1)

(1) Line 1+ Line 3+ Line 5+ Line 7+Line 9+Line 11+Line 13+Line 15

Aquila Networks - NE Rate Area 2 - Jurisdictional
Rate of Return Under Current and Cost of Service Rates
Test Year Ended June 30, 2006

Exhibit___(TJS-4)
Table 1 of 5
Page 1 of 1

	[A]		[B]	[C]	[D]	[E]	[F]
Line Number	Description		Total Res, Comm, Energy Options	Residential	Commercial	Energy Options Firm	Basis of Allocation or Reference
			$	$	$	$	
1	Return Under Existing Rates						
2	Rate Base		64,318,740	49,562,880	11,261,436	3,494,424	
3	Sales Revenues		91,713,614	65,828,173	24,296,860	1,588,580	
4	Cost of Gas		68,334,045	48,633,077	19,700,967	-	
5	Sales Revenues Excluding Gas Cost		23,379,569	17,195,096	4,595,893	1,588,580	
6	Net Cost of Service		29,201,553	23,126,819	4,679,288	1,395,447	
7	Revenue Deficiency		5,821,984	5,931,723	83,395	(193,134)	
8	Percent - Total Sales with Gas Cost		6.35%	9.01%	0.34%	-12.16%	
9	Proposed Increase		7,558,537	7,130,866	338,507	89,163	
10	Percent - Total Sales with Gas Cost		8.24%	10.83%	1.39%	5.61%	
11	Incremental Taxes at	39.15%	2,959,515	2,792,062	132,541	34,911	
12	Incremental Return		4,599,022	4,338,804	205,966	54,251	
13	Return Under Proposed Rates		7,231,212	5,487,660	1,236,322	507,229	
14	Rate of Return Under Proposed Rates		11.24%	11.07%	10.98%	14.52%	
15	Return Under Current Rates		2,632,190	1,148,856	1,030,356	452,978	
16	Rate of Return Under Current Rates		4.09%	2.32%	9.15%	12.96%	

Aquila Networks - NE Rate Area 2 - Jurisdictional
Customer Group Allocation Basis
Test Year Ended June 30, 2006

Line Number	Description		Total Res, Comm, Energy Options	Residential	Commercial	Energy Options Firm	Basis of Allocation or Reference
			$	$	$	$	
	Allocation Bases						
1	1. Winter Period Peak Demand	Load Factor		23.45%	25.88%	25.88%	
2	Peak Day - Dth/Day		96,749	64,879	23,280	8,590	Line 11 / 365 / Line 1
3	Allocation Factor		100.0000%	67.0589%	24.0625%	8.8786%	Line 2 / Column B, Line 2
4	2. Winter Period Throughput						
5	Winter (Nov-Mar) Throughput - Dth		6,037,062	3,952,003	1,509,297	575,762	
6	Allocation Factor		100.0000%	65.4624%	25.0005%	9.5371%	Line 5 / Column B, Line 5
7	3. Firm Winter Period Sales						
8	Winter (Nov-Mar) Sales - Dth		6,037,062	3,952,003	1,509,297	575,762	Line 5
9	Allocation Factor		100.0000%	65.4624%	25.0005%	9.5371%	Line 8 / Column B, Line 8
10	4. Commodity						
11	Annual Throughput - Dth		8,563,482	5,552,571	2,199,380	811,531	
12	Allocation Factor		100.0000%	64.8401%	25.6832%	9.4767%	Line 11 / Column B, Line 11
13	5. Services						
14	Average Number of Customers		91,425	83,700	6,078	1,647	
15	Weighting Factor			1.00	2.00	2.00	Customer Plant Use Study
16	Weighted Number of Customers		99,150	83,700	12,156	3,294	Line 14 x Line 15
17	Services Cost Allocator		100.0000%	84.4175%	12.2602%	3.3222%	Line 16 / Column B, Line 16
18	6. Meters & Regulators						
19	Average Number of Customers		91,425	83,700	6,078	1,647	
20	Weighting Factor			1.00	3.50	3.50	Customer Plant Use Study
21	Weighted Number of Customers		110,738	83,700	21,273	5,765	Line 19 x Line 20
22	Meters & Regulators Cost Allocator		100.0000%	75.5842%	19.2103%	5.2056%	Line 21 / Column B, Line 21
23	7. Customer Accounts						
24	Average Number of Customers		91,425	83,700	6,078	1,647	
25	Weighting Factor			1.00	2.00	2.00	
26	Weighted Number of Customers		99,150	83,700	12,156	3,294	Line 24 x Line 25
27	Customer Accounts Cost Allocator		100.0000%	84.4175%	12.2602%	3.3222%	Line 26 / Column B, Line 26
28	Annual Use per Customer - Dth		1,124	796	4,342	5,913	Line 11 / Line 14 x 12
Summary							
29	Supply - Gas Purchases		100.00%	71.17%	28.83%	0.00%	
30	Peaking		100.00%	65.46%	25.00%	9.54%	
31	Transmission Demand		100.00%	66.27%	24.53%	9.21%	
32	Transmission Commodity		100.00%	64.84%	25.68%	9.48%	
33	Distribution Demand		100.00%	67.06%	24.06%	8.88%	
34	Distribution Commodity		100.00%	64.84%	25.68%	9.48%	
35	Distribution Customer		100.00%	84.42%	12.26%	3.32%	
36	Services		100.00%	84.42%	12.26%	3.32%	
37	Meters & Regulators		100.00%	75.58%	19.21%	5.21%	
38	Customer Accounts		100.00%	84.42%	12.26%	3.32%	

Aquila Networks - NE Rate Area 2 - Jurisdictional
Allocation of Rate Base to Customer Classes
Test Year Ended June 30, 2006

	[A]	[B]	[C]	[D]	[E]	[F]
Line Number	Description	Total Res, Comm, Energy Options	Residential	Commercial	Energy Options Firm	Basis of Allocation or Reference
		$	$	$	$	
1	Rate Base					
2	Supply	898,639	639,558	259,081	0	Cost of Gas
3	Peaking	10,408,501	6,813,650	2,602,179	992,672	Firm Winter Period Sales
4	Transmission					
5	Demand	598,017	396,281	146,684	55,052	50% Winter Period Peak Demand, 50% Winter Period Throughput
6	Commodity	588,724	381,729	151,203	55,791	Commodity
7	Total Transmission	1,186,740	778,010	297,887	110,843	Line 5 + Line 6
8	Distribution					
9	Demand	6,352,589	4,259,978	1,528,589	564,022	Winter Period Peak Demand
10	Commodity	1,753,180	1,136,764	450,273	166,143	Commodity
11	Customer	11,098,568	9,369,139	1,360,708	368,721	Services
12	Total Distribution	19,204,337	14,765,881	3,339,571	1,098,885	Sum of Lines 9 through 11
13	Services	12,115,118	10,227,286	1,485,339	402,493	Services
14	Meters and Regulators	10,796,570	8,160,496	2,074,053	562,021	Meters & Regulators
15	Customer Accounts	9,218,194	7,781,774	1,130,170	306,250	Customer Accounts
16	Direct					
17	Other Cash Working Capital	490,640	396,226	73,156	21,259	Supervised O&M
18	Total Rate Base	64,318,740	49,562,880	11,261,436	3,494,424	Sum of Lines 3, 7, 12, 13,14, 15 and 16

Aquila Networks - NE Rate Area 2 - Jurisdictional
Allocation of Cost of Service to Customer Classes
Test Year Ended June 30, 2006

	[A]	[B]	[C]	[D]	[E]	[F]
Line Number	Description	Total Res, Comm, Energy Options	Residential	Commercial	Energy Options Firm	Basis of Allocation or Reference
		$	$	$	$	
1	Total Cost of Service					
2	Supply	121,472	86,451	35,021	0	Cost of Gas
3	Peaking	1,406,949	921,022	351,745	134,183	Firm Winter Period Sales
4	Transmission					
5	Demand	166,839	110,557	40,923	15,359	50% Winter Period Peak Demand, 50% Winter Period Throughput
6	Commodity	261,933	169,837	67,273	24,822	Commodity
7	Total Transmission	428,771	280,395	108,196	40,181	Line 5 + Line 6
8	Distribution					
9	Demand	2,486,923	1,667,704	598,415	220,804	Winter Period Peak Demand
10	Commodity	1,127,661	731,177	289,620	106,865	Commodity
11	Customer	4,159,312	3,511,189	509,940	138,182	Services
12	Total Distribution	7,773,896	5,910,070	1,397,975	465,851	Sum of Lines 9 through 11
13	Services	5,693,745	4,806,520	698,065	189,160	Services
14	Meters and Regulators	5,232,043	3,954,595	1,005,091	272,357	Meters & Regulators
15	Customer Accounts	8,754,388	7,390,240	1,073,307	290,842	Customer Accounts
16	Direct					
17	Other Cash Working Capital	66,321	53,559	9,889	2,874	Supervised O&M
18	Forfeited Discounts	(276,033)	(276,033)	-	-	Direct
19	Total Cost of Service	29,201,553	23,126,819	4,679,288	1,395,447	Sum of Lines 3, 7, 12, 13,14, 15 and 18

Aquila Networks - NE Rate Area 2 - Jurisdictional
Cost of Service Rate Design
Test Year Ended June 30, 2006

	[A]	[B]	[C]	[D]	[E]	[F]
Line Number	Description	Total Res, Comm, Energy Options	Residential	Commercial	Energy Options Firm	Basis of Allocation or Reference
		$	$	$	$	
1	Supply - Commodity - $	121,472	86,451	35,021	0	Line 1 ,Table 2
2	$/Dth	0.0142	0.0156	0.0159	0.0000	Line 1 / Line 11 ,Table 4
3	Peaking - Demand - $	1,406,949	921,022	351,745	134,183	Line 3 ,Table 2
4	$/Dth	0.1643	0.1659	0.1599	0.1653	Line 3 / Line 11 ,Table 4
5	Transmission - Demand -$	166,839	110,557	40,923	15,359	Line 5 ,Table 2
6	$/Dth	0.0195	0.0199	0.0186	0.0189	Line 5 / Line 11 ,Table 4
7	Transmission - Commodity - $	261,933	169,837	67,273	24,822	Line 6 ,Table 2
8	$/Dth	0.0306	0.0306	0.0306	0.0306	Line 7 / Line 11 ,Table 4
9	Distribution - Demand - $	2,553,244	1,721,263	608,304	223,678	Line 9, Table 2
10	$/Dth	0.2982	0.3100	0.2766	0.2756	Line 9 / Line 11 ,Table 4
11	Distribution - Commodity - $	1,127,661	731,177	289,620	106,865	Line 10, Table 2
12	$/Dth	0.1317	0.1317	0.1317	0.1317	Line 11 / Line 11 ,Table 4
13	Distribution - Customer - $	4,159,312	3,511,189	509,940	138,182	Line 11 ,Table 2
14	$/Dth	0.4857	0.6324	0.2319	0.1703	Line 13 / Line 11 ,Table 4
15	Customer Accounts Related - $	19,404,143	15,875,322	2,776,463	752,358	Line 13 + Line 14 + Line 15 + Line 18, Table 2
16	$/month	17.69	15.81	38.07	38.07	Line 15 / Line 24 ,Table 4 / 12
17	Total Demand - $/Dth		1.1281	0.6870	0.6302	Line 6+Line 10+Line 14
18	Total Commodity - $/Dth		0.1778	0.1782	0.1623	Line 8+Line 12
19	Total - $/Dth		1.3060	0.8652	0.7924	Line 17+Line 18
20	Customer Charge - $/mth		16.00	20.00	20.00	Proposed Rates
21	Volumetric Charge - $/Dth		1.2708	1.4643	1.2324	(Line 22 - Line 20 X Line 24 X 12) / Line 11
22	Total Cost of Service - $	29,201,553	23,126,819	4,679,288	1,395,447	(1)

(1) Line 3+ Line 5+ Line 7+Line 9+Line 11+Line 13+Line 15

Aquila Networks - NE Rate Area 3 - Jurisdictional
Rate of Return Under Current and Cost of Service Rates
Test Year Ended June 30, 2006

	[A]		[B]	[C]	[D]	[E]	[F]
Line Number	Description		Total Res, Comm, Energy Options	Residential	Commercial	Energy Options Firm	Basis of Allocation or Reference
			$	$	$	$	
1	Return Under Existing Rates						
2	Rate Base		43,849,026	31,269,679	8,427,023	4,152,325	
3	Sales Revenues		74,642,325	53,490,472	19,137,252	2,014,601	
4	Cost of Gas		57,241,728	41,469,344	15,772,383	-	
5	Sales Revenues Excluding Gas Cost		17,400,597	12,021,128	3,364,868	2,014,601	
6	Net Cost of Service		22,807,118	16,612,716	4,203,960	1,990,443	
7	Revenue Deficiency		5,406,521	4,591,588	839,092	(24,159)	
8	Percent - Total Sales with Gas Cost		7.24%	8.58%	4.38%	-1.20%	
9	Proposed Increase		4,913,442	4,304,902	413,110	195,430	
10	Percent - Total Sales with Gas Cost		6.58%	8.05%	2.16%	9.70%	
11	Incremental Taxes at	39.15%	1,923,839	1,685,567	161,751	76,520	
12	Incremental Return		2,989,603	2,619,335	251,358	118,910	
13	Return Under Proposed Rates		3,909,491	2,827,454	549,803	532,233	
14	Rate of Return Under Proposed Rates		8.92%	9.04%	6.52%	12.82%	
15	Return Under Current Rates		919,887	208,119	298,445	413,323	
16	Rate of Return Under Current Rates		2.10%	0.67%	3.54%	9.95%	

Aquila Networks - NE Rate Area 3 - Jurisdictional
Customer Group Allocation Basis
Test Year Ended June 30, 2006

Line Number	Description		Total Res, Comm, Energy Options	Residential	Commercial	Energy Options Firm	Basis of Allocation or Reference
			$	$	$	$	
	Allocation Bases						
1	1. Winter Period Peak Demand	Load Factor		23.32%	26.96%	26.96%	
2	Peak Day - Dth/Day		74,341	47,894	15,817	10,629	Line 11 / 365 / Line 1
3	Allocation Factor		100.0000%	64.4255%	21.2769%	14.2976%	Line 2 / Column B, Line 2
4	2. Winter Period Throughput						
5	Winter (Nov-Mar) Throughput - Dth		4,845,567	2,981,217	1,114,858	749,492	
6	Allocation Factor		100.0000%	61.5246%	23.0078%	15.4676%	Line 5 / Column B, Line 5
7	3. Firm Winter Period Sales						
8	Winter (Nov-Mar) Sales - Dth		4,845,567	2,981,217	1,114,858	749,492	Line 5
9	Allocation Factor		100.0000%	61.5246%	23.0078%	15.4676%	Line 8 / Column B, Line 8
10	4. Commodity						
11	Annual Throughput - Dth		6,678,714	4,076,114	1,556,602	1,045,999	
12	Allocation Factor		100.0000%	61.0314%	23.3069%	15.6617%	Line 11 / Column B, Line 11
13	5. Services						
14	Average Number of Customers		61,280	53,467	5,492	2,321	
15	Weighting Factor			1.00	2.00	2.00	Customer Plant Use Study
16	Weighted Number of Customers		69,093	53,467	10,984	4,642	Line 14 x Line 15
17	Services Cost Allocator		100.0000%	77.3841%	15.8974%	6.7185%	Line 16 / Column B, Line 16
18	6. Meters & Regulators						
19	Average Number of Customers		61,280	53,467	5,492	2,321	
20	Weighting Factor			1.00	3.50	3.50	Customer Plant Use Study
21	Weighted Number of Customers		80,813	53,467	19,222	8,124	Line 19 x Line 20
22	Meters & Regulators Cost Allocator		100.0000%	66.1618%	23.7859%	10.0523%	Line 21 / Column B, Line 21
23	7. Customer Accounts						
24	Average Number of Customers		61,280	53,467	5,492	2,321	
25	Weighting Factor			1.00	2.00	2.00	
26	Weighted Number of Customers		69,093	53,467	10,984	4,642	Line 24 x Line 25
27	Customer Accounts Cost Allocator		100.0000%	77.3841%	15.8974%	6.7185%	Line 26 / Column B, Line 26
28	Annual Use per Customer - Dth		1,308	915	3,401	5,408	Line 11 / Line 14 x 12
Summary							
29	Supply - Gas Purchases		100.00%	72.45%	27.55%	0.00%	
30	Peaking		100.00%	61.52%	23.01%	15.47%	
31	Transmission Demand		100.00%	62.99%	22.13%	14.88%	
32	Transmission Commodity		100.00%	61.03%	23.31%	15.66%	
33	Distribution Demand		100.00%	64.43%	21.28%	14.30%	
34	Distribution Commodity		100.00%	61.03%	23.31%	15.66%	
35	Distribution Customer		100.00%	77.38%	15.90%	6.72%	
36	Services		100.00%	77.38%	15.90%	6.72%	
37	Meters & Regulators		100.00%	66.16%	23.79%	10.05%	
38	Customer Accounts		100.00%	77.38%	15.90%	6.72%	

Aquila Networks - NE Rate Area 3 - Jurisdictional
Allocation of Rate Base to Customer Classes
Test Year Ended June 30, 2006

Exhibit___(TJS-5)
Table 3 of 5

	[A]	[B]	[C]	[D]	[E]	[F]
Line Number	Description	Total Res, Comm, Energy Options	Residential	Commercial	Energy Options Firm	Basis of Allocation or Reference
		$	$	$	$	
1	Rate Base					
2	Supply	752,768	545,350	207,418	0	Cost of Gas
3	Peaking	4,326,112	2,661,625	995,343	669,145	Firm Winter Period Sales
4	Transmission					
5	Demand	27,110	17,078	6,000	4,033	50% Winter Period Peak Demand, 50% Winter Period Throughput
6	Commodity	26,036	15,890	6,068	4,078	Commodity
7	Total Transmission	53,146	32,968	12,068	8,110	Line 5 + Line 6
8	Distribution					
9	Demand	5,991,183	3,859,847	1,274,740	856,595	Winter Period Peak Demand
10	Commodity	1,836,991	1,121,142	428,146	287,704	Commodity
11	Customer	9,815,361	7,595,530	1,560,389	659,443	Services
12	Total Distribution	17,643,535	12,576,519	3,263,275	1,803,742	Sum of Lines 9 through 11
13	Services	10,991,011	8,505,296	1,747,287	738,429	Services
14	Meters and Regulators	7,505,416	4,965,718	1,785,232	754,466	Meters & Regulators
15	Customer Accounts	2,209,666	1,709,931	351,280	148,456	Customer Accounts
16	Direct					
17	Other Cash Working Capital	367,371	272,273	65,121	29,977	Supervised O&M
18	Total Rate Base	43,849,026	31,269,679	8,427,023	4,152,325	Sum of Lines 3, 7, 12, 13,14, 15 and 16

Aquila Networks - NE Rate Area 3 - Jurisdictional
Allocation of Cost of Service to Customer Classes
Test Year Ended June 30, 2006

Exhibit___(TJS-5)
Table 4 of 5
Page 1 of 1

	[A]	[B]	[C]	[D]	[E]	[F]
Line Number	Description	Total Res, Comm, Energy Options	Residential	Commercial	Energy Options Firm	Basis of Allocation or Reference
		$	$	$	$	
1	Total Cost of Service					
2	Supply	101,754	73,717	28,037	0	Cost of Gas
3	Peaking	584,774	359,780	134,544	90,450	Firm Winter Period Sales
4	Transmission					
5	Demand	14,278	8,994	3,160	2,124	50% Winter Period Peak Demand, 50% Winter Period Throughput
6	Commodity	89,898	54,866	20,953	14,080	Commodity
7	Total Transmission	104,176	63,860	24,112	16,203	Line 5 + Line 6
8	Distribution					
9	Demand	2,318,970	1,494,007	493,406	331,557	Winter Period Peak Demand
10	Commodity	1,078,221	658,053	251,300	168,867	Commodity
11	Customer	3,524,828	2,727,657	560,356	236,815	Services
12	Total Distribution	6,922,019	4,879,717	1,305,062	737,239	Sum of Lines 9 through 11
13	Services	5,049,837	3,907,771	802,794	339,272	Services
14	Meters and Regulators	3,564,293	2,358,200	847,800	358,293	Meters & Regulators
15	Customer Accounts	6,622,513	5,124,773	1,052,808	444,932	Customer Accounts
16	Direct					
17	Other Cash Working Capital	49,659	36,804	8,803	4,052	Supervised O&M
18	Forfeited Discounts	(191,907)	(191,907)	-	-	Direct
19	Total Cost of Service	22,807,118	16,612,716	4,203,960	1,990,443	Sum of Lines 3, 7, 12, 13,14, 15 and 18

Aquila Networks - NE Rate Area 3 - Jurisdictional
Cost of Service Rate Design
Test Year Ended June 30, 2006

	[A]	[B]	[C]	[D]	[E]	[F]
Line Number	Description	Total Res, Comm, Energy Options	Residential	Commercial	Energy Options Firm	Basis of Allocation or Reference
		$	$	$	$	
1	Supply - Commodity - $	101,754	73,717	28,037	0	Line 1 ,Table 2
2	$/Dth	0.0152	0.0181	0.0180	0.0000	Line 1 / Line 11 ,Table 4
3	Peaking - Demand - $	584,774	359,780	134,544	90,450	Line 3 ,Table 2
4	$/Dth	0.0876	0.0883	0.0864	0.0865	Line 3 / Line 11 ,Table 4
5	Transmission - Demand -$	14,278	8,994	3,160	2,124	Line 5 ,Table 2
6	$/Dth	0.0021	0.0022	0.0020	0.0020	Line 5 / Line 11 ,Table 4
7	Transmission - Commodity - $	89,898	54,866	20,953	14,080	Line 6 ,Table 2
8	$/Dth	0.0135	0.0135	0.0135	0.0135	Line 7 / Line 11 ,Table 4
9	Distribution - Demand - $	2,368,629	1,530,811	502,209	335,609	Line 9, Table 2
10	$/Dth	0.3547	0.3756	0.3226	0.3209	Line 9 / Line 11 ,Table 4
11	Distribution - Commodity - $	1,078,221	658,053	251,300	168,867	Line 10, Table 2
12	$/Dth	0.1614	0.1614	0.1614	0.1614	Line 11 / Line 11 ,Table 4
13	Distribution - Customer - $	3,524,828	2,727,657	560,356	236,815	Line 11 ,Table 2
14	$/Dth	0.5278	0.6692	0.3600	0.2264	Line 13 / Line 11 ,Table 4
15	Customer Accounts Related - $	15,044,736	11,198,837	2,703,402	1,142,497	Line 13 + Line 14 + Line 15 + Line 18, Table 2
16	$/month	20.46	17.45	41.02	41.02	Line 15 / Line 24 ,Table 4 / 12
17	Total Demand - $/Dth		1.1352	0.7711	0.6358	Line 6+Line 10+Line 14
18	Total Commodity - $/Dth		0.1930	0.1929	0.1749	Line 8+Line 12
19	Total - $/Dth		1.3282	0.9640	0.8107	Line 17+Line 18
20	Customer Charge - $/mth		16.00	20.00	20.00	Proposed Rates
21	Volumetric Charge - $/Dth		1.5571	1.8540	1.3704	(Line 22 - Line 20 X Line 24 X 12) / Line 11
22	Total Cost of Service - $	22,807,118	16,612,716	4,203,960	1,990,443	(1)

(1) Line 3+ Line 5+ Line 7+Line 9+Line 11+Line 13+Line 15

Exhibit___(TJS-6)

Aquila Networks - NE
Proposed Rates
Jurisdictional Rate Areas

	[A]	[B]	[C]
Line Number	Description	Customer Charge	Commodity Charge
		$/month	$/therm
1	Residential	16.00	0.14868
2	Commercial	20.00	0.15803
3	Energy Options	20.00	0.15803

Applicable to Rate Areas 1, 2, and 3

Aquila Networks - NE
Proposed Rate Design

Line	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
		Existing		Test Year									ROR Under
		Customer Charge	Commodity Charge	Number of Customers	Throughput	Customer Charge	Commodity Charge	Total Margin	Cost of Gas	Total Revenues	Cost of Service	Indicated Deficiency	Current Rates
		$/bill/mo	$/therm		dt	$	$	$	$	$	$	$	
1	**Rate Areas 1-3**												
2	Residential			173,463	12,447,759	22,897,140	14,201,859	37,098,999	116,381,801	153,480,800	51,812,123	14,713,124	1.06%
3	Commercial			14,490	4,558,984	2,608,200	6,897,974	9,506,174	42,865,727	52,371,901	11,270,040	1,763,866	5.26%
4	Energy Options Firm			4,441	2,155,564	799,380	3,267,445	4,066,825	-	4,066,825	3,884,662	(182,164)	10.86%
5	Total			192,394	19,162,307	26,304,720	24,367,278	50,671,998	159,247,529	209,919,527	66,966,824	16,294,826	
6	Fixed/Variable Recovery					51.91%	48.09%	100.00%					
7													
8	**Total RA 1**												
9	Residential	11.00	0.10967	36,296	2,819,074	4,791,096	3,091,679	7,882,775	26,279,380	34,162,155	12,072,589	4,189,814	-1.01%
10	Commercial	15.00	0.12700	2,920	803,002	525,600	1,019,813	1,545,413	7,392,376	8,937,789	2,386,792	841,379	-0.54%
11	Energy Options Firm	15.00	0.12700	473	298,034	85,140	378,504	463,644	-	463,644	498,772	35,129	7.78%
12	Total			39,689	3,920,111	5,401,836	4,489,995	9,891,831	33,671,756	43,563,588	14,958,153	5,066,322	
13	Fixed/Variable Recovery					54.61%	45.39%	100.00%					
14													
15	**Total RA 2**												
16	Residential	11.00	0.11070	83,700	5,552,571	11,048,400	6,146,696	17,195,096	48,633,077	65,828,173	23,126,819	5,931,723	2.32%
17	Commercial	15.00	0.15922	6,078	2,199,380	1,094,040	3,501,853	4,595,893	19,700,967	24,296,860	4,679,288	83,395	9.15%
18	Energy Options Firm	15.00	0.15922	1,647	811,531	296,460	1,292,120	1,588,580	-	1,588,580	1,395,447	(193,134)	12.96%
19	Total			91,425	8,563,482	12,438,900	10,940,669	23,379,569	68,334,045	91,713,614	29,201,553	5,821,984	
20	Fixed/Variable Recovery					53.20%	46.80%	100.00%					
21													
22	**Total RA 3**												
23	Residential	11.00	0.12177	53,467	4,076,114	7,057,644	4,963,484	12,021,128	41,469,344	53,490,472	16,612,716	4,591,588	0.67%
24	Commercial	15.00	0.15266	5,492	1,556,602	988,560	2,376,308	3,364,868	15,772,383	19,137,252	4,203,960	839,092	3.54%
25	Energy Options Firm	15.00	0.15266	2,321	1,045,999	417,780	1,596,821	2,014,601	-	2,014,601	1,990,443	(24,159)	9.95%
26	Total			61,280	6,678,714	8,463,984	8,936,613	17,400,597	57,241,728	74,642,325	22,807,118	5,406,521	
27	Fixed/Variable Recovery					48.64%	51.36%	100.00%					
28													
29	**Total Rate Areas 1-3**			192,394	19,162,307	26,304,720	24,367,278	50,671,998	159,247,529	209,919,527	66,966,824	16,294,826	
30	Fixed/Variable Recovery					51.91%	48.09%	100.00%					

Aquila Networks - NE
Proposed Rate Design

	[A]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]	[U]	[V]	[W]	[X]	[Y]	[Z]	[AA]
		Proposed		Revenues Under Proposed										ROR Under	
		Customer	Commodity	Customer	Commodity	Total		Total	Proposed Increase					Proposed	
		Charge	Charge	Charge	Charge	Margin	Cost of Gas	Revenues	$	%	Comm+EO	% (exc. COG)	Comm+EO	Rates	Comm+EO
		$/bill/mo	$/therm	$	$	$	$	$							
1	**Rate Areas 1-3**														
2	Residential	16.00	0.14868	33,304,896	18,507,328	51,812,224	116,381,801	168,194,025	14,713,225	9.59%		39.66%		9.60%	
3	Commercial	20.00	0.15803	3,477,600	7,204,563	10,682,163	42,865,727	53,547,890	1,175,989	2.25%	2.80%	12.37%	11.65%	8.15%	9.60%
4	Energy Options Firm	20.00	0.15803	1,065,840	3,406,438	4,472,278	-	4,472,278	405,453	9.97%		9.97%		13.65%	
5	Total			37,848,336	29,118,329	66,966,665	159,247,529	226,214,194	16,294,667	7.76%		32.16%			
6	Fixed/Variable Recovery			56.52%	43.48%	100.00%									
7															
8	**Total RA 1**														
9	Residential	16.00	0.14868	6,968,832	4,191,400	11,160,232	26,279,380	37,439,612	3,277,457	9.59%		41.58%		7.29%	
10	Commercial	20.00	0.15803	700,800	1,268,985	1,969,785	7,392,376	9,362,161	424,372	4.75%	5.80%	27.46%	27.14%	4.57%	6.36%
11	Energy Options Firm	20.00	0.15803	113,520	470,984	584,504	-	584,504	120,860	26.07%		26.07%		14.05%	
12	Total			7,783,152	5,931,368	13,714,520	33,671,756	47,386,276	3,822,689	8.77%		38.64%		7.10%	
13	Fixed/Variable Recovery			56.75%	43.25%	100.00%									
14															
15	**Total RA 2**														
16	Residential	16.00	0.14868	16,070,400	8,255,562	24,325,962	48,633,077	72,959,039	7,130,866	10.83%		41.47%		11.07%	
17	Commercial	20.00	0.15803	1,458,720	3,475,680	4,934,400	19,700,967	24,635,368	338,507	1.39%	1.65%	7.37%	6.92%	10.98%	11.82%
18	Energy Options Firm	20.00	0.15803	395,280	1,282,463	1,677,743	-	1,677,743	89,163	5.61%		5.61%		14.52%	
19	Total			17,924,400	13,013,706	30,938,106	68,334,045	99,272,150	7,558,537	8.24%		32.33%		11.24%	
20	Fixed/Variable Recovery			57.94%	42.06%	100.00%									
21															
22	**Total RA 3**														
23	Residential	16.00	0.14868	10,265,664	6,060,366	16,326,030	41,469,344	57,795,374	4,304,902	8.05%		35.81%		9.04%	
24	Commercial	20.00	0.15803	1,318,080	2,459,898	3,777,978	15,772,383	19,550,361	413,110	2.16%	2.88%	12.28%	11.31%	6.52%	8.60%
25	Energy Options Firm	20.00	0.15803	557,040	1,652,992	2,210,032	-	2,210,032	195,430	9.70%		9.70%		12.82%	
26	Total			12,140,784	10,173,255	22,314,039	57,241,728	79,555,767	4,913,442	6.58%		28.24%		8.92%	
27	Fixed/Variable Recovery			54.41%	45.59%	100.00%									
28															
29	**Total Rate Areas 1-3**			37,848,336	29,118,329	66,966,665	159,247,529	226,214,194	16,294,667	7.76%		32.16%			
30	Fixed/Variable Recovery			56.52%	43.48%	100.00%									

Aquila Networks - NE
Alternative 1 - Traditional Rate Design Structure (1)
Increase Customer Charge Only

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
		Existing		Test Year									ROR Under
		Customer Charge	Commodity Charge	Number of Customers	Throughput	Customer Charge	Commodity Charge	Total Margin	$9.24/dt Cost of Gas	Total Revenues	Cost of Service	Indicated Deficiency	Current Rates
		$/bill/mo	$/therm		dt	$	$	$	$	$	$	$	
1	**Rate Areas 1-3**												
2	Residential			173,463	12,447,759	22,897,140	14,201,859	37,098,999	116,381,801	153,480,800	51,812,123	14,713,124	1.06%
3	Commercial			14,490	4,558,984	2,608,200	6,897,974	9,506,174	42,865,727	52,371,901	11,270,040	1,763,866	5.26%
4	Energy Options Firm			4,441	2,155,564	799,380	3,267,445	4,066,825	-	4,066,825	3,884,662	(182,164)	10.86%
5	Total			192,394	19,162,307	26,304,720	24,367,278	50,671,998	159,247,529	209,919,527	66,966,824	16,294,826	
6	Fixed/Variable Recovery					51.91%	48.09%	100.00%					
7													
8	**Rate Area 1**												
9	Residential	11.00	0.10967	36,296	2,819,074	4,791,096	3,091,679	7,882,775	26,279,380	34,162,155	12,072,589	4,189,814	-1.01%
10	Commercial	15.00	0.12700	2,920	803,002	525,600	1,019,813	1,545,413	7,392,376	8,937,789	2,386,792	841,379	-0.54%
11	Energy Options Firm	15.00	0.12700	473	298,034	85,140	378,504	463,644	-	463,644	498,772	35,129	7.78%
12	Total			39,689	3,920,111	5,401,836	4,489,995	9,891,831	33,671,756	43,563,588	14,958,153	5,066,322	
13	Fixed/Variable Recovery					54.61%	45.39%	100.00%					
14								-					
15	**Rate Area 2**												
16	Residential	11.00	0.11070	83,700	5,552,571	11,048,400	6,146,696	17,195,096	48,633,077	65,828,173	23,126,819	5,931,723	2.32%
17	Commercial	15.00	0.15922	6,078	2,199,380	1,094,040	3,501,853	4,595,893	19,700,967	24,296,860	4,679,288	83,395	9.15%
18	Energy Options Firm	15.00	0.15922	1,647	811,531	296,460	1,292,120	1,588,580	-	1,588,580	1,395,447	(193,134)	12.96%
19	Total			91,425	8,563,482	12,438,900	10,940,669	23,379,569	68,334,045	91,713,614	29,201,553	5,821,984	
20	Fixed/Variable Recovery					53.20%	46.80%	100.00%					
21								-					
22	**Rate Area 3**												
23	Residential	11.00	0.12177	53,467	4,076,114	7,057,644	4,963,484	12,021,128	41,469,344	53,490,472	16,612,716	4,591,588	0.67%
24	Commercial	15.00	0.15266	5,492	1,556,602	988,560	2,376,308	3,364,868	15,772,383	19,137,252	4,203,960	839,092	3.54%
25	Energy Options Firm	15.00	0.15266	2,321	1,045,999	417,780	1,596,821	2,014,601	-	2,014,601	1,990,443	(24,159)	9.95%
26	Total			61,280	6,678,714	8,463,984	8,936,613	17,400,597	57,241,728	74,642,325	22,807,118	5,406,521	
27	Fixed/Variable Recovery					48.64%	51.36%	-					
28								-					
29	**Total Rate Areas 1-3**			192,394	19,162,307	26,304,720	24,367,278	50,671,998	159,247,529	209,919,527	66,966,824	16,294,826	
30	Fixed/Variable Recovery					51.91%	48.09%	100.00%					

(1) All of the proposed revenue increase is collected through increasing the existing customer charges. Equalize existing commodity charges among Rate Areas.

Aquila Networks - NE
Alternative 1 - Traditional Rate Design Structure [(1)]
Increase Customer Charge Only

	[A]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]	[U]	[V]	[W]	[X]	[Y]	[Z]	[AA]
		Alternative 1		Revenues Under Alternative 1										ROR Under	
		Customer	Commodity	Customer	Commodity	Total		Total	Alternative 1 Increase					Alt. 1	
		Charge	Charge	Charge	Charge	Margin	Cost of Gas	Revenues	$	% (incl. COG)	Comm+EO	% (exc. COG)	Comm+EO	Rates	Comm+EO
		$/bill/mo	$/therm	$	$	$	$	$							
1	**Rate Areas 1-3**														
2	Residential	18.07	0.11409	37,610,264	14,201,859	51,812,123	116,381,801	168,193,924	14,713,124	9.59%		39.66%		9.60%	
3	Commercial	21.96	0.15139	3,818,853	6,902,026	10,720,878	42,865,727	53,586,606	1,214,704	2.32%	2.80%	12.78%	11.65%	8.25%	9.60%
4	Energy Options Firm	21.96	0.15139	1,170,430	3,263,394	4,433,823	-	4,433,823	366,998	9.02%		9.02%		13.39%	
5	Total			42,599,546	24,367,278	66,966,824	159,247,529	226,214,353	16,294,826	7.76%		32.16%		9.60%	
6	Fixed/Variable Recovery			63.61%	36.39%	100.00%									
7															
8	**Rate Area 1**														
9	Residential	18.07	0.11409	7,869,702	3,216,329	11,086,032	26,279,380	37,365,412	3,203,257	9.38%		40.64%			
10	Commercial	21.96	0.15139	769,569	1,215,697	1,985,266	7,392,376	9,377,642	439,853	4.92%	5.87%	28.46%	27.48%		
11	Energy Options Firm	21.96	0.15139	124,660	451,206	575,866	-	575,866	112,222	24.20%		24.20%			
12	Total			8,763,930	4,883,232	13,647,163	33,671,756	47,318,919	3,755,331	8.62%		37.96%			
13	Fixed/Variable Recovery			64.22%	35.78%	100.00%									
14															
15	**Rate Area 2**														
16	Residential	18.07	0.11409	18,147,842	6,335,022	24,482,864	48,633,077	73,115,941	7,287,768	11.07%		42.38%			
17	Commercial	21.96	0.15139	1,601,862	3,329,728	4,931,591	19,700,967	24,632,558	335,698	1.38%	1.58%	7.30%	6.63%		
18	Energy Options Firm	21.96	0.15139	434,068	1,228,609	1,662,678	-	1,662,678	74,097	4.66%		4.66%			
19	Total			20,183,773	10,893,359	31,077,132	68,334,045	99,411,177	7,697,563	8.39%		32.92%			
20	Fixed/Variable Recovery			64.95%	35.05%	100.00%									
21															
22	**Rate Area 3**														
23	Residential	18.07	0.11409	11,592,720	4,650,507	16,243,227	41,469,344	57,712,572	4,222,099	7.89%		35.12%			
24	Commercial	21.96	0.15139	1,447,422	2,356,601	3,804,022	15,772,383	19,576,406	439,154	2.29%	2.93%	13.05%	11.52%		
25	Energy Options Firm	21.96	0.15139	611,702	1,583,578	2,195,280	-	2,195,280	180,679	8.97%		8.97%			
26	Total			13,651,843	8,590,686	22,242,529	57,241,728	79,484,257	4,841,932	6.49%		27.83%			
27	Fixed/Variable Recovery			61.38%	38.62%	100.00%									
28															
29	**Total Rate Areas 1-3**			42,599,546	24,367,278	66,966,824	159,247,529	226,214,353	16,294,826	7.76%		32.16%			
30	Fixed/Variable Recovery			63.61%	36.39%	100.00%									

(1) All of the proposed revenue increase is collected through increasing the existing customer charges. Equalize existing commodity charges among Rate Areas.

Aquila Networks - NE
Alternative 2 - Flat Charge Approach

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
		Existing		Test Year									ROR Under
		Customer Charge	Commodity Charge	Number of Customers	Throughput	Customer Charge	Commodity Charge	Total Margin	$9.24/dt Cost of Gas	Total Revenues	Cost of Service	Indicated Deficiency	Current Rates
		$/bill/mo	$/therm		dt	$	$	$	$	$	$	$	
1	**Rate Areas 1-3**												
2	Residential			173,463	12,447,759	22,897,140	14,201,859	37,098,999	116,381,801	153,480,800	51,812,123	14,713,124	1.06%
3	Commercial			14,490	4,558,984	2,608,200	6,897,974	9,506,174	42,865,727	52,371,901	11,270,040	1,763,866	5.26%
4	Energy Options Firm			4,441	2,155,564	799,380	3,267,445	4,066,825	-	4,066,825	3,884,662	(182,164)	10.86%
5	Total			192,394	19,162,307	26,304,720	24,367,278	50,671,998	159,247,529	209,919,527	66,966,824	16,294,826	
6	Fixed/Variable Recovery					51.91%	48.09%	100.00%					
7													
8	**Rate Area 1**												
9	Residential	11.00	0.10967	36,296	2,819,074	4,791,096	3,091,679	7,882,775	26,279,380	34,162,155	12,072,589	4,189,814	-1.01%
10	Commercial	15.00	0.12700	2,920	803,002	525,600	1,019,813	1,545,413	7,392,376	8,937,789	2,386,792	841,379	-0.54%
11	Energy Options Firm	15.00	0.12700	473	298,034	85,140	378,504	463,644	-	463,644	498,772	35,129	7.78%
12	Total			39,689	3,920,111	5,401,836	4,489,995	9,891,831	33,671,756	43,563,588	14,958,153	5,066,322	
13	Fixed/Variable Recovery					54.61%	45.39%	100.00%					
14								-					
15	**Rate Area 2**												
16	Residential	11.00	0.11070	83,700	5,552,571	11,048,400	6,146,696	17,195,096	48,633,077	65,828,173	23,126,819	5,931,723	2.32%
17	Commercial	15.00	0.15922	6,078	2,199,380	1,094,040	3,501,853	4,595,893	19,700,967	24,296,860	4,679,288	83,395	9.15%
18	Energy Options Firm	15.00	0.15922	1,647	811,531	296,460	1,292,120	1,588,580	-	1,588,580	1,395,447	(193,134)	12.96%
19	Total			91,425	8,563,482	12,438,900	10,940,669	23,379,569	68,334,045	91,713,614	29,201,553	5,821,984	
20	Fixed/Variable Recovery					53.20%	46.80%	100.00%					
21								-					
22	**Rate Area 3**												
23	Residential	11.00	0.12177	53,467	4,076,114	7,057,644	4,963,484	12,021,128	41,469,344	53,490,472	16,612,716	4,591,588	0.67%
24	Commercial	15.00	0.15266	5,492	1,556,602	988,560	2,376,308	3,364,868	15,772,383	19,137,252	4,203,960	839,092	3.54%
25	Energy Options Firm	15.00	0.15266	2,321	1,045,999	417,780	1,596,821	2,014,601	-	2,014,601	1,990,443	(24,159)	9.95%
26	Total			61,280	6,678,714	8,463,984	8,936,613	17,400,597	57,241,728	74,642,325	22,807,118	5,406,521	
27	Fixed/Variable Recovery					48.64%	51.36%	-					
28								-					
29	**Total Rate Areas 1-3**			192,394	19,162,307	26,304,720	24,367,278	50,671,998	159,247,529	209,919,527	66,966,824	16,294,826	
30	Fixed/Variable Recovery					51.91%	48.09%	100.00%					

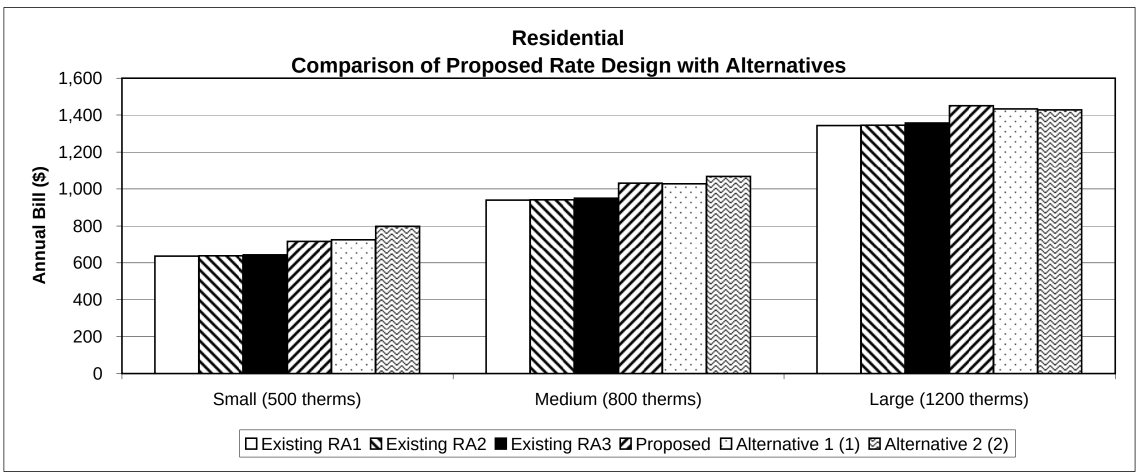
Aquila Networks - NE
Alternative 2 - Flat Charge Approach

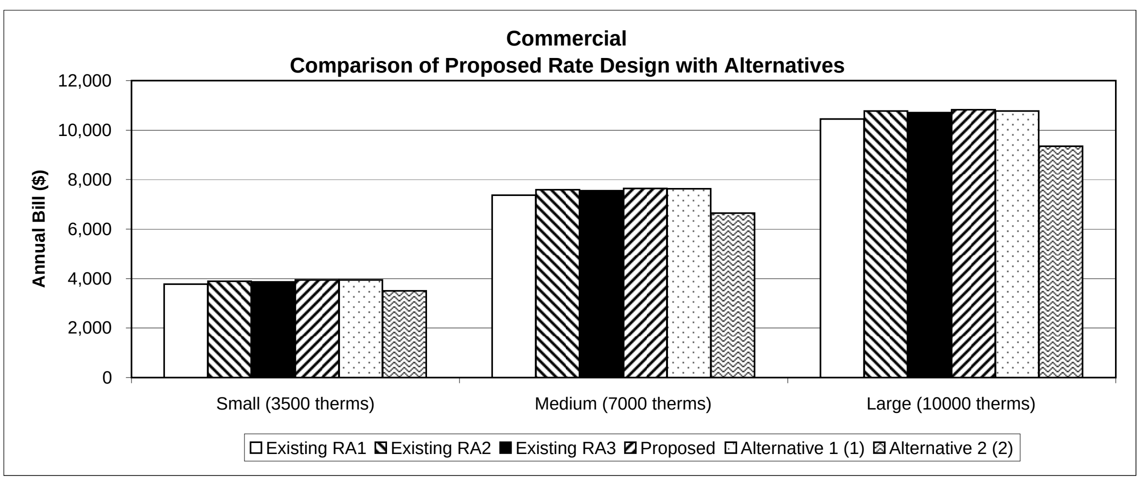
	[A]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]	[U]	[V]	[W]	[X]	[Y]	[Z]	[AA]
		Alternative 2		Revenues Under Alternative 2										ROR Under	
		Customer	Commodity	Customer	Commodity	Total		Total	Alternative 2 Increase					Alt. 2	
		Charge	Charge	Charge	Charge	Margin	Cost of Gas	Revenues	$	% (incl. COG)	Comm+EO	% (exc. COG)	Comm+EO	Rates	Comm+EO
		$/bill/mo	$/therm	$	$	$	$	$							
1	**Rate Areas 1-3**														
2	Residential	29.01	0.00000	60,377,487	-	60,377,487	116,381,801	176,759,288	23,278,489	15.17%		62.75%		14.57%	
3	Commercial	29.01	0.00000	5,043,553	-	5,043,553	42,865,727	47,909,280	(4,462,621)	-8.52%	-12.37%	-46.94%	-51.45%	-5.72%	-5.93%
4	Energy Options Firm	29.01	0.00000	1,545,785	-	1,545,785	-	1,545,785	(2,521,041)	-61.99%		-61.99%		-6.54%	
5	Total			66,966,824	-	66,966,824	159,247,529	226,214,353	16,294,826	7.76%		32.16%		9.60%	
6	Fixed/Variable Recovery			100.00%	0.00%	100.00%									
7															
8	**Rate Area 1**														
9	Residential	29.01	-	12,633,595	-	12,633,595	26,279,380	38,912,975	4,750,820	13.91%		60.27%			
10	Commercial	29.01	-	1,016,368	-	1,016,368	7,392,376	8,408,744	(529,045)	-5.92%	-8.81%	-34.23%	-41.22%		
11	Energy Options Firm	29.01	-	164,638	-	164,638	-	164,638	(299,006)	-64.49%		-64.49%			
12	Total			13,814,601	-	13,814,601	33,671,756	47,486,357	3,922,769	9.00%		39.66%			
13	Fixed/Variable Recovery			100.00%	0.00%	100.00%									
14															
15	**Rate Area 2**														
16	Residential	29.01	-	29,133,565	-	29,133,565	48,633,077	77,766,643	11,938,470	18.14%		69.43%			
17	Commercial	29.01	-	2,115,577	-	2,115,577	19,700,967	21,816,545	(2,480,316)	-10.21%	-13.50%	-53.97%	-56.52%		
18	Energy Options Firm	29.01	-	573,273	-	573,273	-	573,273	(1,015,307)	-63.91%		-63.91%			
19	Total			31,822,416	-	31,822,416	68,334,045	100,156,461	8,442,847	9.21%		36.11%			
20	Fixed/Variable Recovery			100.00%	0.00%	100.00%									
21															
22	**Rate Area 3**														
23	Residential	29.01	-	18,610,327	-	18,610,327	41,469,344	60,079,671	6,589,199	12.32%		54.81%			
24	Commercial	29.01	-	1,911,607	-	1,911,607	15,772,383	17,683,991	(1,453,261)	-7.59%	-12.58%	-43.19%	-49.45%		
25	Energy Options Firm	29.01	-	807,873	-	807,873	-	807,873	(1,206,728)	-59.90%		-59.90%			
26	Total			21,329,808	-	21,329,808	57,241,728	78,571,535	3,929,210	5.26%		22.58%			
27	Fixed/Variable Recovery			100.00%	0.00%	100.00%									
28															
29	**Total Rate Areas 1-3**			66,966,824	-	66,966,824	159,247,529	226,214,353	16,294,826	7.76%		32.16%			
30	Fixed/Variable Recovery			100.00%	0.00%	100.00%									

Aquila Networks - NE
Typical Bills Under Existing, Proposed, and Alternative Rate Designs

	Annual Usage	Existing RA1	Existing RA2	Existing RA3	Proposed	Alternative 1 (1)	Alternative 2 (2)
	therms	$	$	$	$	$	$
Residential							
Small (500 therms)	500	637	637	643	716	724	798
Medium (800 therms)	800	940	941	949	1,031	1,028	1,068
Large (1200 therms)	1,200	1,344	1,345	1,358	1,450	1,434	1,428
Commercial							
Small (3500 therms)	3,500	3,775	3,887	3,864	3,943	3,943	3,498
Medium (7000 therms)	7,000	7,369	7,595	7,549	7,646	7,623	6,648
Large (10000 therms)	10,000	10,450	10,772	10,707	10,820	10,777	9,348

Assumed cost of gas = $9/dt





(1) Alternative 1 - All of the proposed revenue increase is collected through increasing the existing customer charges. Equalize existing commodity charges among Rate Areas.
(2) Alternative 2 - Flat charge approach.